Economic Regulation Authority

Triennial review of the effectiveness of the Wholesale Electricity Market 2022

Discussion paper

29 July 2022

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Invitation to make submissions

Submissions are due by 4:00 pm WST, Sunday 28 August

The ERA invites comment on this paper and encourages all interested parties to provide comment on the matters discussed in this paper and any other issues or concerns not already raised in this paper.

We would prefer to receive your comments via our online submission form https://www.erawa.com.au/consultation

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Please note that submissions provided electronically do not need to be provided separately in hard copy.

All submissions will be made available on our website unless arrangements are made in advance between the author and the ERA. This is because it is preferable that all submissions be publicly available to facilitate an informed and transparent consultative process. Parties wishing to submit confidential information are requested to contact us at info@erawa.com.au.

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1. Executive summary

The *Electricity Industry Act 2004* (WA) establishes five objectives for the Wholesale Electricity Market (WEM) and requires the Economic Regulation Authority to triennially assess the extent to which the WEM is achieving these objectives.

The ERA has adopted a forward-looking approach for this triennial review to consider how well the WEM objectives will be achieved in the future. In its previous reviews of the WEM, the ERA adopted a retrospective approach by considering recent outcomes in the WEM to identify any gaps in how the market meets its objectives. The ERA considers a retrospective approach is not useful for this review due to the substantial changes underway in the WEM, including the new market start scheduled for October 2023.

This review focuses on the WEM objectives of ensuring a reliable supply of electricity at the lowest sustainable cost to consumers. Achieving these objectives requires price signals that drive the efficient investment in and operation of resources to deliver power system services. Without efficient price signals, new investment in the WEM will neither meet the needs of the market, nor support the WEM to achieve the State Government's economy-wide goal of net zero by 2050. The ERA has looked into this issue in the context of the new market. This discussion paper outlines the ERA's preliminary findings and seeks stakeholder input for the ERA's report to the Minister for Energy.

As renewable generation and storage have different operational and cost characteristics to thermal generation, the current WEM price signals will not drive the investment required to meet the needs of the South West Interconnected System (SWIS) in the future. The ERA's preliminary analysis indicates that existing price signals do not provide an adequate commercial justification for investing in the new, low emission generation and storage in a way that would meet the WEM objectives.

The ERA has identified two challenges to efficient investment:

- As thermal generation exits the market, market prices for energy will decrease and progressively lower the profit margin on the additional renewables and storage that are required to replace the thermal generation exiting the market. This will mean that renewable energy facilities will not generate sufficient revenue in the energy market to drive investment.
- For battery storage the combined revenue from participation in energy, essential system services and reserve capacity provision is likely to be inadequate to cover investment costs. Preliminary modelling indicates that revenue generated from providing essential system services, which currently represents the bulk of the total revenue for batteries, substantially decreases with the sequential entry of battery storage across the power system.[1]

These challenges must be addressed as new investment in conventional thermal generation becomes more costly, risky and contrary to government policy and social demand for low emission generation. State Government policies are supporting this transition through the closure of Synergy's coal-fired power plants by 2030 and the commitment to no new natural gas-fired power stations after 2030.

1 Essential systems services are services that support the system operator to manage short-term and unexpected changes in the balance of supply and demand. In the new market, this is expected to include services from battery storage facilities that are able to store electricity during low demand periods and supply that electricity during periods of high demand.

Meeting electricity demand will require low emissions technology to enter the WEM at the right scale and within the right timeframe. Rapidly scaling up electricity storage and its participation in the energy market will address the variability which characterises wind and solar energy sources and periods of low demand.

Incentivising investments that provide the highest benefit with the lowest cost to both the SWIS and to investors will support the WEM to achieve its objectives as the system transitions to lower level of emissions.

The ERA acknowledges that the State Government's review of the reserve capacity mechanism is likely to partially fill the revenue gap required to incentivise investment in storage and renewable generation. However, further initiatives will be needed to provide efficient price signals if the net zero emissions target is to be achieved on time and at the lowest sustainable cost to electricity consumers.

The ERA is seeking feedback from stakeholders on this discussion paper and any other matters relevant to the ERA's review. Submissions are required by 28 August 2022.

The ERA will consider all relevant feedback when preparing its final report, which will be presented to the Minister for Energy by 11 October 2022.

2. Introduction

Under the *Electricity Industry Act 2004*, the Economic Regulation Authority is required to review the extent to which the Wholesale Electricity Market (WEM) objectives have been or are being achieved. The ERA must conduct this review every three years and prepare a report for the Minister for Energy on its findings.[2] Excerpts from the Act that guide the ERA's review are provided in Appendix 4.

The WEM objectives are to:

- Promote the economically efficient, safe and reliable production and supply of electricity and electricity-related services in the South West Interconnected System (SWIS).
- Encourage competition among generators and retailers in the SWIS, including by facilitating efficient entry of new competitors.
- Avoid discrimination in the SWIS against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions.
- Minimise the long-term cost of electricity supplied to customers from the SWIS.
- Encourage the taking of measures to manage the amount of electricity used and when it is used.[3]

If the ERA considers that some or all of the objectives have not been and are not being achieved, the ERA must provide recommendations as to how those objectives can be achieved.

The ERA must provide its report to the Minister for Energy by 11 October 2022. The Minister must, as soon as practicable after receiving the report, table the report and a response in Parliament.[4]

2.1 Context of this review

The ERA is undertaking the current triennial review at a time when energy markets globally are transitioning away from conventional fossil fuel generation, such as coal and gas, to renewable low marginal cost technologies like wind and solar and large-scale storage technologies, supported by international targets for reducing emissions.[5]

The WEM is part of the transition in the way that electricity is supplied and used. Households and small businesses have installed solar photovoltaic (PV) and battery systems while large-scale renewable generators are supplying an increasing amount of electricity.[6] This transition is expected to accelerate.[7]

[2] Electricity Industry Act 2004, 7 April 2020, Clause 128, (online).

[3] Wholesale Electricity Market Rules (WA), 1 July 2022, Rule 1.2.1, (online).

[4] Relevant excerpts from the Act are provided in Appendix 4.

[5] United Nations Sustainable Development Goals Knowledge Platform: Climate Change, (online). International Renewable Energy Agency, Energy Transition, (online). International Energy Agency, World Energy Model: Net Zero Emissions by 2050 Scenario (NZE), (online).

[6] Energy Policy WA, Energy Transformation Strategy, (online).

[7] Government of Western Australia media statement, 10 May 2022, WA's Climate Action Efforts Accelerate with $60 million EV Package, (online) [accessed 1 June 2022]

In March 2019, the State Government announced its Energy Transformation Strategy (ETS) to enable the WEM's transition to a more decentralised, lower-emissions market via the integration of more distributed energy resources (DER) in the system.[8, 9]

The new WEM, set to commence in October 2023, is another initiative to assist with this transition. The ETS is currently reviewing the reserve capacity mechanism, preparing the second Whole of System Plan (WOSP), developing initiatives to enable the transition to low-emissions energy and DER, and maintaining security and reliability through the transition.[10,11]

The ETS is supported by the Western Australian Climate Policy and State Electric Vehicle Strategy, which set out a range of initiatives to support the State Government's target to achieve net zero greenhouse gas emissions economy-wide by 2050.[12] Initiatives include supporting the net zero transition across the public sector; promoting low-carbon energy, mining and agriculture; and guiding decarbonisation across the State's economy.[13]

The State Government has announced that Synergy will close its coal-fired power plants by 2030 and invest approximately $3.8 billion in new green power infrastructure in the SWIS.[14] In addition, by 2030 all State Government entities, including Synergy, are obliged to reduce emissions to 80 per cent below 2020 levels.[15]

The pace and scope of the transformation occurring in the WEM may present significant challenges to the security of the power system which has been developed around conventional generation such as coal- and gas-fired generation. The Australian Energy Market Operator (AEMO) outlined the effect that the implementation of renewables is already having on the power system and will have on the future power system.[16]

A rapid scaling up of storage installations in the system is required to provide the flexibility (such as ramping services) needed to mitigate variation in supply and demand as more renewables enter the system.

Price signals in the SWIS must be effective to ensure that there is always sufficient generation available to meet short-term operational demand and long-term variation in demand, at the lowest cost possible. This is important to meet the WEM's objectives to ensure a reliable electricity supply and to minimise the long-term cost of that supply.

8 Energy Policy WA, 2021, Leading Western Australia's brighter energy future – Energy Transformation Strategy – Stage 2: 2021-2025, (online).

9 DER includes distributed photovoltaic, distributed battery storage, and electric vehicles. Australian Energy Market Operator (June 2022). 2022 Wholesale Electricity Market Electricity Statement of Opportunities: A report for the Wholesale Electricity Market, p. 106, (online).

10 The RCM is a market mechanism that allows the market operator to procure capacity to ensure that adequate generation is available to meet periods of peak demand for electricity. See: Energy Policy Western Australia, 2022, Reserve Capacity Mechanism Review Working Group, (online).

11 Energy Policy WA, July 2021, Leading Western Australia's Brighter Energy Future: Energy Transformation Strategy. Stage 2: 2021-2025, (online).

12 Department of Water and Environmental Regulation, 2020, Western Australian Climate Policy, (online) and State Electric Vehicle Strategy, (online).

13 Government of Western Australia media statement, 22 April 2022, $4.2 million R&D Investment to Reduce Carbon Emissions and Achieve Net Zero by 2050, (online) [accessed 14 July 2022].

14 Government of Western Australia media statement, 14 June 2022, State-Owned Coal Power Stations to be Retired by 2030, (online) [accessed 14 July 2022].

15 Government of Western Australia media statement, 23 June 2022, Ambitious Interim Target Set for State Government Emissions, (online) [accessed 14 July 2022].

16 Australian Energy Market Operator, 2022, 2022 Wholesale Electricity Market Electricity Statement of Opportunities: A report for the Wholesale Electricity Market, p. 7, (online)

2.2 The ERA's approach to this triennial review

In its previous reviews, the ERA adopted a retrospective approach by considering recent outcomes in the WEM to identify any gaps in how the market meets its objectives. A retrospective approach is not useful for this triennial review as the current market reforms will substantially change the WEM design going forward, making any recommendations by the ERA redundant.

Accordingly, the ERA has adopted a forward-looking approach for this triennial review to consider how the WEM objectives will be achieved in the future.

In particular, the ERA is evaluating how the WEM objectives of ensuring the economically efficient, safe, and reliable production and supply of electricity and electricity-related services to the SWIS at the least cost to consumers, can be achieved during the rapid decarbonisation and transformation of the electricity sector and the broader economy. Specifically, the ERA has sought to answer the following question:

> **Can the WEM achieve its objectives as the energy industry transforms and the State economy decarbonises?**

If the WEM objectives cannot be met, new initiatives may be needed. These initiatives may, for example, be targeted to ensure commercial investment in renewable generation and storage facilities occur when they are needed and at the lowest possible cost.

To address the question, the ERA has worked with Energy Policy WA (EPWA) to understand the reforms being implemented in the WEM. The ERA also analysed market data, modelled possible market outcomes for the inclusion of storage technology in the system, reviewed practices and outcomes for batteries in international jurisdictions, and considered information provided by market participants.

The ERA is seeking feedback and empirical evidence from stakeholders on the analysis and findings in this discussion paper. Written submissions may be provided to the ERA during the 30-day consultation period. Appendix 3 lists questions to guide stakeholder feedback. Information received in response to this consultation process will inform the ERA's report to the Minister for Energy.

3. Implications for investment in the WEM

Electricity markets seek to provide price signals to stimulate investment and ensure adequate generation capacity to meet the system's operational requirements. For example, energy market prices increase to reflect energy supply scarcity. In addition, the price of ancillary services – to be known in the new market as essential system services (ESS) – increases to signal the value of a fast response to restore the balance between energy supply and demand, to maintain system reliability.

Efficient price signals are necessary to drive the investment in renewable technologies required to replace exiting thermal generators. This discussion paper outlines analyses undertaken to determine whether the price signals will allow large-scale wind and solar generation and battery storage facilities to be commercially feasible and deliver the services required by the market, as the economy decarbonises.

This section first considers the current WEM design and how the operational and cost differences between conventional and renewable generation are affecting price signals for new investment in the WEM. Section 3.2 then considers future price signals given the timing of the carbon emissions constraint of achieving net zero by 2050.

The ERA's analysis shows that available price signals do not account for the operational and cost characteristics of renewable generation and storage. Without efficient price signals, investment in renewable generation and storage will be inadequate to meet the WEM objectives while the market transitions.

3.1 Current price signals

The WEM has been designed to ensure supply and demand variability is managed at the lowest sustainable cost. Price signals in the WEM are sufficient to ensure the mix of resources available in the system provides all services required to resolve system constraints.[17] The combined revenue from participation in the energy market, provision of ESS, and the reserve capacity mechanism (RCM) has driven investment in additional supply where and when necessary.

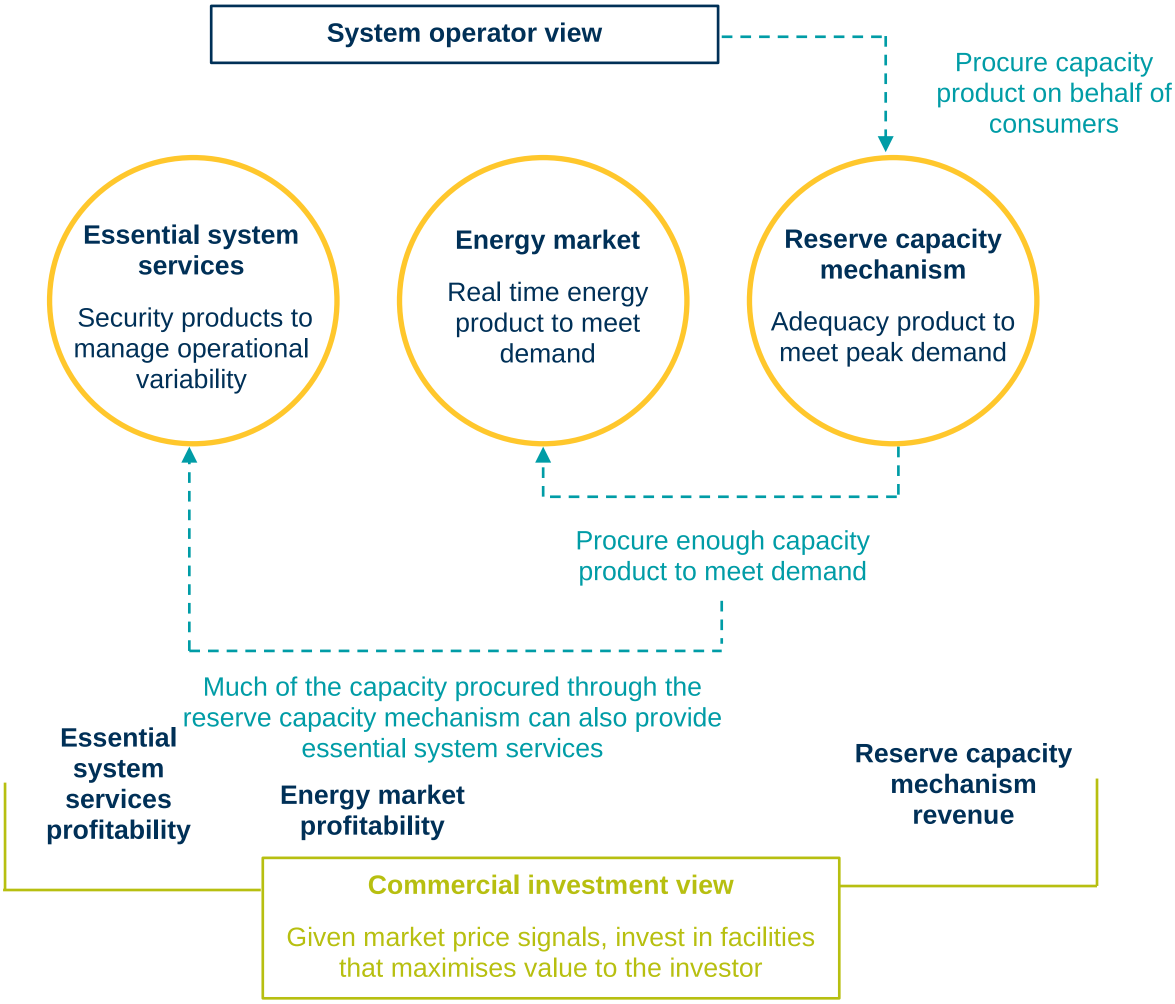
The price signals are suited to the operational and cost characteristics of thermal generators. However, the price signals are unlikely to encourage the efficient entry of renewables and battery storage as the share of thermal generation in the WEM decreases.

Figure 1 summarises the three revenue streams that WEM participants and new entrants base their investment decisions on.[18] This includes the ESS markets which will replace ancillary services when the new market commences in October 2023.

[17] Examples of system constraint include: available capacity must be more than demand; the voltage and frequency must be within standard range; the system must be able to restart from a total blackout; and the level of emissions generated must not exceed targets set for the SWIS.

[18] Other incentives in the market such as bilateral contracts for the provision of system restart service and network support service could also provide benefits to facilities but are not represented in figure 1.

Figure 1: Expected revenue streams for WEM participants in the current market.



Generators are paid for providing ESS that ensure the reliability of electricity supply.[19] Market participants may also receive capacity credits through the RCM. Many thermal resources that receive reserve capacity credits, such as gas turbines and coal plants, will also be able to participate in ESS markets after new market start.[20]

Capacity credits are based on the fixed costs for a new entrant liquid-fuelled open cycle gas turbine, known as the benchmark reserve capacity price (BRCP).[21] Capacity credit pricing seeks to emulate a competitive auction for procuring capacity. The BRCP reflects the annualised fixed costs of the benchmark facility and is the capacity price that, if paid to the

19 ESS comprises five system security services. See EPWA, 2019, Essential Systems Services – Scheduling and Dispatch, (online).

20 The reserve capacity mechanism in the WEM compensates facilities for their contribution to meeting peak demand – reflected through the assignment of capacity credits to facilities. For a facility, the revenue from participation in the RCM is in proportion to the number of capacity credits assigned to the facility.

21 The State Government's review of the RCM includes a review of the methodology to set the BRCP. This review will address some of the issues identified in this discussion paper. However, ERA's consideration of capacity payments is in relation to the broader implications of revenue sufficiency for renewables and storage, in general. For more information see the Scope of Works and Terms of Reference for the Reserve Capacity Mechanism Review Working Group (online)

benchmark facility over its economic life, would be just sufficient to encourage the entry of the benchmark plant to connect to the WEM. [22, 23]

Participating in the RCM provides investors in thermal generation with reasonable certainty about the recovery of fixed investment and operational costs. In proportion to their installed capacity, thermal generators receive a substantial amount of capacity credits. In comparison, due to their intermittency, renewables receive fewer capacity credits in proportion to their installed capacity.[24]

The main revenue stream for renewables is currently from the energy market and renewable energy certificates.[25] The accreditation of facilities and assignment of renewable energy certificates will cease in 2030. Revenue available to renewables from the sale of renewable energy certificates is expected to decrease toward 2030 as the large-scale renewable energy target will remain constant while the supply of renewable energy increases.

Renewable generation and storage are required to replace the existing conventional, thermal generation and provide the range of services required as the SWIS decarbonises. As renewable generation is typically reliant on the weather, there will be a growing need for flexible services to manage intermittency in the system. At the same time, due to the low operational cost of renewables, prices in the energy market reduce leading to a possible deficiency of signals to invest in capacity that provides flexibility.

3.2 Required price signals

The RCM does not explicitly signal scarcity of flexible capacity in the system to manage operational variability. The price signals provided through the RCM reflect scarcity of capacity only during periods of peak demand, and do not reflect the value of flexible resources to the system for controlling short-term variation in supply and demand.

The increasing share of renewable generation and storage will increase demand for services to manage operational variability making this signal critically important. One of the market design reforms includes the commencement of the Supplementary ESS Mechanism (SESSM), which will mitigate scarcity in flexibility capacity by allowing AEMO to procure ESS capacity.[26] However, relying on backstop mechanisms, like the SESSM, to procure flexible capacity may risk system reliability and increase the long-term cost of supply.[27]

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22 The ERA must annually determine the BRCP according to the BRCP Market Procedure. See: Wholesale Electricity Market Rules (WA), 1 July 2022, Rule 4.16.5, and Market Procedure: Benchmark Reserve Capacity Price (WA), 9 November 2020.

23 The capacity price is determined based on the capacity credit price curve and the BRCP. The BRCP is determined by the ERA and is a bottom-up cost assessment of building a new, 160 MW gas generator as required by the WEM Rules – Wholesale Electricity Market Rules (WA), 1 July 2022, Rule 4.29.1.

24 The available capacity from wind and solar generators is intermittent and variable such that these facilities cannot contribute to meeting peak demand in the system with the same reliability as thermal generation can. The assignment of capacity credits to wind and solar factors in the variability of their output and limits their capacity credits to a portion of their installed capacity.

25 The Large-scale Renewable Energy Target incentivises the development of renewable energy power stations. Power stations accredited in the LRET are able to create LGCs for electricity generated from that power station's renewable energy sources. LGCs can then be sold to entities with liabilities under the LRET (mainly electricity retailers) to meet their compliance obligations. See: Clean Energy Regulator (online).

26 Energy Policy WA, 2020, Supplementary ESS Procurement Mechanism – Information Paper, (online).

27 For example, the SESSM concerns the existing set of ESS only. If the system requires ramping flexibility, it must be first defined as a new ESS service to allow the SESSM to procure the service. For information about the SESSM mechanism refer to Energy Transformation Taskforce, 2022, Supplementary ESS Procurement Mechanism, Information Paper, 24 April 2020, (online).

The State Government's review of the RCM includes the procurement of flexible capacity alongside the procurement of the existing capacity product. The RCM review is considering how to procure flexible capacity with fast-start capability, low availability restrictions (such as minimum generation limits) and fast ramping capability.[28] The RCM review is also expected to consider the method for measuring the contribution of resources to meeting system adequacy. This is discussed in section 4.3 of this paper.

The RCM review is expected to improve revenue sufficiency for flexible capacity, which can be provided by battery storage facilities. However, that will not fully account for the revenue sufficiency problem arising from the increased penetration of renewable energy. For example, price signals are to account for the contribution that is needed from new renewable generation and storage to meet the State's emission reduction targets.

To support a discussion of the price signals required in the WEM, the ERA's preliminary modelling results are presented in section 3. These results will be finalised for the ERA's report to the Minister for Energy in October 2022.

[28] Energy Policy WA, 2022, Meeting agenda: Reserve capacity mechanism working group, 14 July 2022, (online).

4. Commercial investments to meet the WEM objectives

In this discussion paper, the ERA considered the WEM objectives of ensuring the economically efficient, safe, and reliable production and supply of electricity and electricity-related services to the SWIS at minimal cost to consumers, and whether they can be achieved during the rapid decarbonisation and transformation of the electricity sector and the broader economy.

Section 4.1 outlines the ERA's analysis of whether there will be sufficient revenue for renewable generators and battery storage to encourage investors to enter the WEM. This modelling has adopted a top-down, long-term capacity planning method to understand changes in the capacity mix and minimise the long-term supply cost of electricity in the WEM. A lack of sufficient investment could risk system reliability, increase the cost of electricity supply to consumers, and may delay achievement of the State Government's emissions reduction target.

Section 4.2 outlines a second modelling approach, involving a bottom-up investment analysis, to provide a more nuanced understanding of factors that drive investment in battery storage that cannot be achieved through a top-down approach alone.[29] The analysis focuses on large-scale battery storage, as these facilities can play a key role in the evolving WEM, providing energy and ESS, and a valuable source of flexibility, leading to better reliability outcomes. Battery storage can also provide several other benefits to the WEM, such as:

- Reducing development costs by sharing interconnection facilities.
- Reducing network costs by:
  - Improving the performance and efficiency of solar or wind resources by reducing curtailments (when resources are told to shut down or reduce generation in response to reduced demand or transmission constraints).
  - Deferring transmission upgrades.
- Helping the market to preserve a limited fuel supply for the hours when fuel is most needed.

The ERA's analysis also considered whether complementary measures are needed to ensure third-party investment in renewable generation and storage facilities, and whether they will occur at the right time and at the lowest possible cost to meet the WEM objectives, whilst contributing to the State's net zero goal. These measures are considered in section 4.3.

Alongside maximising value for shareholders, companies now account for environmental, social and governance risks. For example, companies may factor in the social cost of emissions when making commercial investments.

4.1 Revenue sufficiency

The ERA and its consultants conducted modelling to assess whether the price signals in the WEM will drive investments in large-scale renewable energy technologies and battery storage to replace exiting thermal generation. The ERA has also modelled different emissions

[29] A top-down approach involves long-term capacity mix planning to minimise the supply cost of electricity in the WEM. In contrast, a bottom-up approach uses a discounted cash flow analysis based on expected cash flows from participation across the WEM to assess investment feasibility for batteries.

scenarios that are possible from electricity generation in the SWIS, and whether the market will provide the investment needed to ensure a reliable and efficient supply of electricity.

The revenue adequacy for large-scale wind, solar and battery storage in the WEM was determined by modelling a baseline scenario reflecting the WEM's current generation mix and emissions.[30,31] The model was then run over several scenarios, each reflecting a different supply mix, with an increasing level of wind, solar and battery storage replacing thermal generation, at decreasing levels of emissions, while minimising the supply cost of electricity. For each technology, and each future technology mix scenario, the model compared annual net revenue from participating in the energy market to the annualised fixed investment and operation costs.

Top-down modelling to assess revenue sufficiency

The model comprised two components: a long-term capacity optimisation component and a short-term dispatch model component. The long-term component determined the mix of generation and storage facilities that must enter or exit the WEM to minimise the supply cost of electricity, subject to meeting a given level of demand and an emissions target. This long-term component considered investment and operational costs for facilities.

The short-term component then used the supply mix results from the long-term component and determined the optimal dispatch outcomes for meeting system demand at the lowest cost possible. This way the model dispatched facilities in order of operational costs to meet demand. This component of the model provided revenues from participation in the WEM.

This modelling is a simplified representation of the WEM. The model assessed changes in energy market revenue and does not include possible revenues from the ESS markets for several reasons. For wind and solar facilities, revenue from ESS markets was expected to be small, and thus, does not influence the general findings. For RCM revenue projections, the modelling used an expected average capacity credit (as a proportion of installed capacity) and the current reserve capacity price.[32]

Long-term ESS revenue for batteries was not included in the battery storage modelling. The ERA's consultants, Endgame Economics, reasoned that over the long-term, battery storage revenue from ESS markets would substantially decrease as more energy storage facilities enter the market. This substantial decline in ESS revenues for storage is confirmed by the ERA's own modelling of battery storage participation in the WEM (see section 3.2). The ERA's modelling shows that revenue from ESS markets provides the bulk of revenue for battery storage facilities at low levels of battery storage competition.

The modelling results are discussed below. The consultant's report is included at Appendix 7.

30 A facility providing services to the WEM achieves revenue sufficiency and is profitable when it can expect to recover its costs, including a reasonable risk-adjusted return on investment. Critical to this assessment is a facility's expected revenue from providing these various WEM services.

31 0Appendix 7 explains Endgame Economics' modelling approach. Endgame used a long-term planning model to determine capacity retirements and builds to minimise the long-term supply cost of electricity in the WEM.

32 The analysis used the current capacity price paid to transitional facilities. For more details about this analysis refer to sections 4.1.1 and 4.1.2.

4.1.1 Preliminary model results

The preliminary results indicate that prices in the WEM will not be high enough to support revenue sufficiency for wind, solar and battery storage facilities as more solar, wind and storage facilities enter the WEM, and coal and gas generators exit the market.

The extent of the gap between the revenue received and the revenue required by these renewable energy facilities grows as more of them replace thermal generation. This is because as more solar and wind generators with negligible operational costs enter the market, they set the energy market price at or close to zero more frequently. As a result, all generators in the WEM will face lower and lower prices, which do not allow them to recover their initial investment costs.

4.1.1.1 Wind generation

The preliminary modelling has demonstrated that the annualised revenue, net of variable costs, for wind generators is insufficient to cover annualised fixed costs across all emissions levels (Figure 2). This indicates that the energy market revenue will not be sufficient to drive investments in the wind generation facilities that will be required to replace thermal generation and achieve lower levels of emissions.

The modelling also demonstrated that:

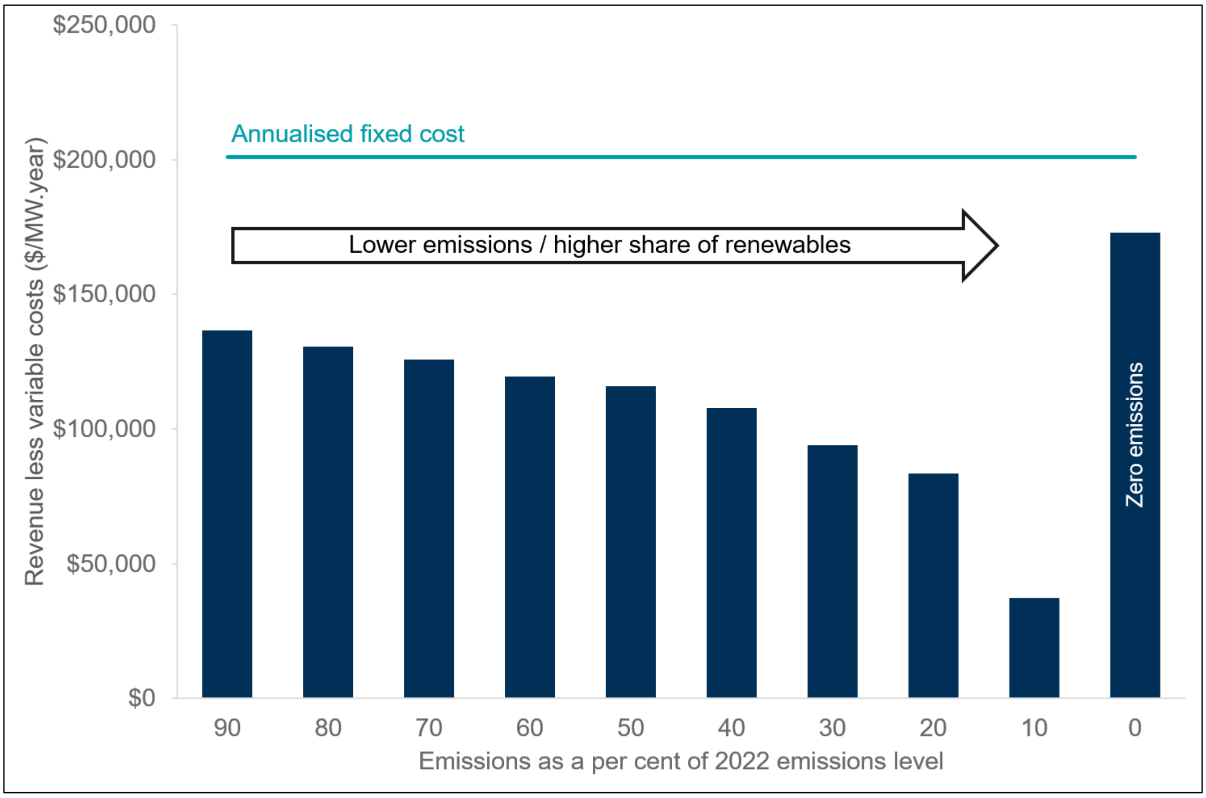
- Wind generators cannot offset this revenue deficiency by participating in the RCM.[33] This is because wind generators do not make a substantial contribution to meeting peak demand in the system, and therefore, the number of capacity credits they receive is a small fraction of their installed capacity.
- The extent of revenue insufficiency grows as the level of emissions decreases (except for the zero emissions scenario).

In Figure 2, the rise in revenue from the 10 to zero per cent emissions scenario is driven by energy price spikes that occur more frequently in the zero emissions scenario. At the level of zero emissions, the system faces 59 periods of unmet demand during which energy market prices rise to reflect the value of lost load. This increases average energy market prices, and hence revenue for generators that provide energy during those periods in the system.[34]

[33] Endgame Economics estimated an average $35,600 per installed MW per year revenue from the RCM for wind generators. This revenue is not sufficient to cover the revenue shortfall for wind generators. The estimated revenue was based on the reserve capacity price for transitional facilities and 30 per cent of installed capacity assigned as capacity credits to wind generators. Under the WEM Rules transitional facilities are those for which the capacity price is bounded by a floor and a cap. The current price paid to transitional facilities (for the capacity year 2023/24) is $118,599 per MW per year.

[34] Based on the modelling assumptions, the cost associated with installing additional battery storage exceeds cost to consumers of shedding load.

Figure 2: Revenue sufficiency for wind generation facilities[35]



Source: Endgame Economics

Note: the emissions target on the horizontal axis reflects emissions as a per cent of the current level of emissions in the WEM. For example, a 40 per cent emissions target indicates emissions cannot exceed 40 per cent of the current total emissions. A 100 per cent emissions target is not included along the horizontal axis as it reflects the current status of the WEM.

4.1.1.2 Solar generation

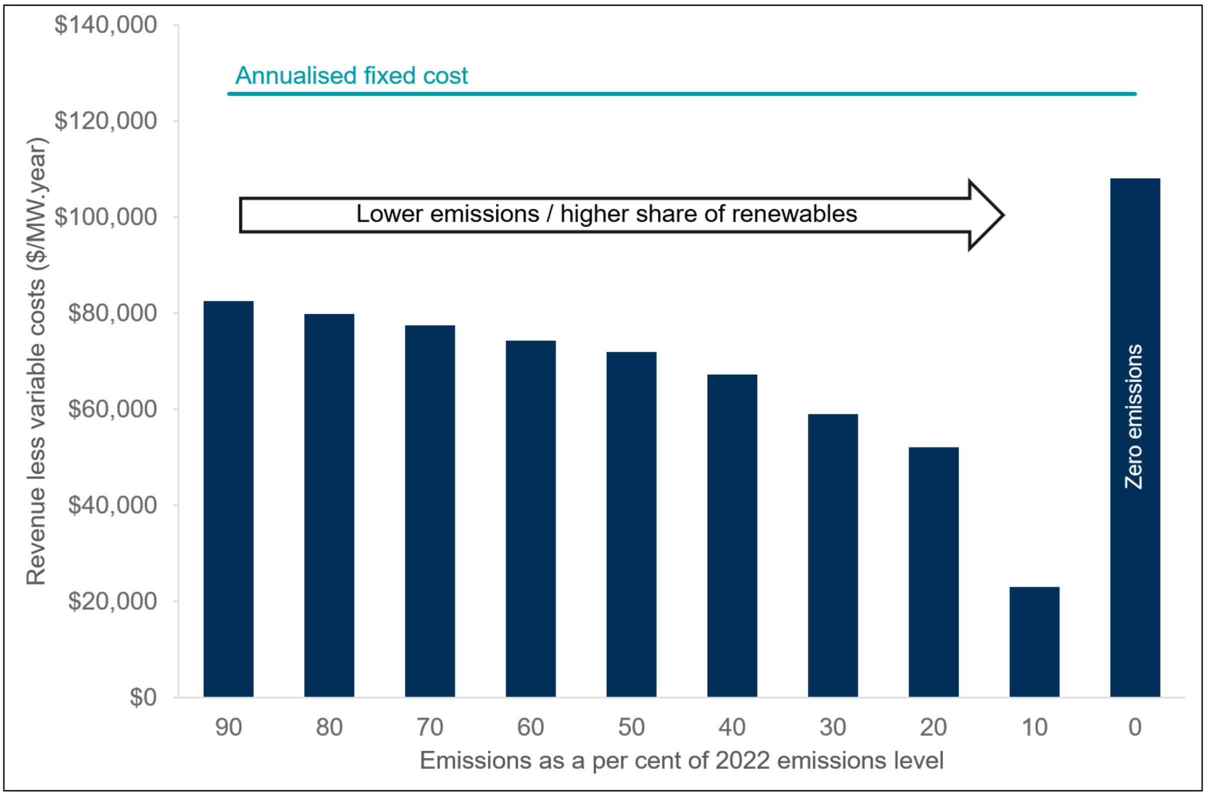
The modelling results for solar generation facilities yielded similar results to that for wind generation (Figure 3).[36]

Revenue from participating in the energy market is not sufficient to drive investments in solar generation facilities to the levels required to replace thermal generation and lower emissions. Solar generators cannot offset this revenue deficiency by participating in the RCM. Like wind, solar generators do not make a substantial contribution to meeting peak demand in the system, and therefore, the number of capacity credits they receive is a small fraction of their installed capacity.

35 This figure refers to installed megawatts.

36 Refer to Appendix 7 for further detail on the modelling.

Figure 3: Revenue sufficiency for solar generation facilities[37]



Source: Endgame Economics

Note: the emissions target on the horizontal axis reflects emissions as a per cent of the current level of emissions in the WEM. For example, a 40 per cent emissions target indicates emissions cannot exceed 40 per cent of the current total emissions.

4.1.1.3 Battery storage

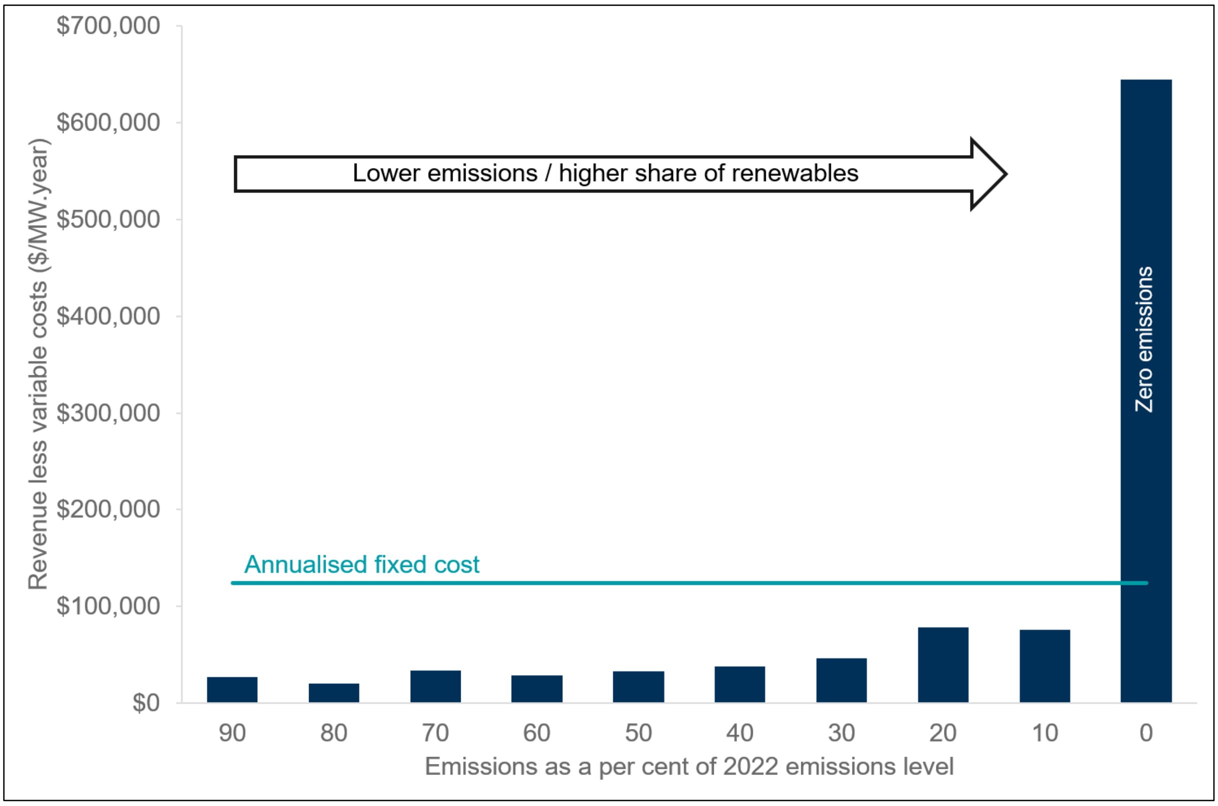
The modelling results for battery storage identify that revenue will be insufficient unless the market operates at high penetration levels of wind and solar generation when emissions decrease to near zero (Figure 4). This observation was driven by low price variation in the energy market, which limits the possibility for battery storage earning profits from storing energy during low energy price periods and selling when market prices rise.[38] At extremely low levels of emissions, when the share of wind and solar generation is high, battery storage will benefit from price spikes in the energy market when they rise to reflect scarcity of energy, during periods demand is unmet.

ESS revenue was not included in the long-term modelling. This exclusion does not limit the ERA's analysis as revenue earnt by battery storage for providing ESS is likely to decrease rapidly when more battery storage enters the market and energy market prices decrease. The ERA's results in Figure 5 illustrate this decline in ESS revenue for batteries.

37 This figure refers to installed megawatts.

38 This is known as energy arbitrage.

Figure 4: Revenue sufficiency for battery storage facilities[39]



Source: Endgame Economics

Note: the emissions target on the horizontal axis reflects emissions as a per cent of the current level of emissions in the WEM. For example, a 40 per cent emissions target indicates emissions cannot exceed 40 per cent of the current total emissions.

Section 4.2 provides a detailed analysis of the investment case for batteries, having consideration for the operational characteristics of battery storage and their participation in the WEM.

4.2 Investment case for battery storage

The need for grid connected storage options, like batteries, comes from installing variable renewable energy technologies, such as wind and solar generation, the outputs of which are dependent on the weather. As more renewables connect to the SWIS, more flexibility services are needed to ensure that the variability of supply does not compromise the electricity system's reliability.

The price signals in the WEM currently may not encourage the efficient entry of battery storage to provide flexible resources. Flexibility is required, for example, to meet the fast-rising demand for electricity when the sun sets and rooftop solar PV stops generating.

Other sources of flexibility in the system include fast-response gas turbine generators, demand side programmes, and distributed energy resources. However, investment in gas generation plants has become less appealing as the development cost for renewables and battery storage is decreasing. No new gas plant has entered the SWIS since 2012 and the State Government has committed to not commission any new natural gas-fired power stations in the SWIS after

39 This figure refers to installed megawatts.

2030.[40,41] Additionally, the supply of flexibility from demand response and distributed energy resources might be limited and insufficient to meet additional demand for flexibility services.

The ERA has evaluated the investment case for battery storage using a bottom-up approach to understand the issues, drivers and likelihood of battery investment in the WEM. Battery storage facilities can earn revenue in the WEM by participating in the following markets:

- The real-time balancing market. A battery's primary use is to store energy for later use. A battery can earn revenue by charging (i.e., buying) when the electricity price is low, and discharging (i.e., selling) when the price is high. This is called energy arbitrage. This is commercially viable when the difference between the buy and sell prices is greater than the cost of cycling the battery, the cost associated with energy losses, and the expected profit from using the stored energy for ESS.
- The ESS markets. A battery is a highly flexible source of electricity that can provide many ESS services. Participating in ESS markets is attractive for battery operators as the battery earns revenue by offering its services into the market without cycling, unless dispatched. Less cycling helps to prolong the life of the battery.
- The reserve capacity mechanism. Capacity credits are allocated to electricity providers based on how much capacity they can make available to the WEM during periods when the system requires the most capacity to maintain system reliability.[42] Batteries will receive capacity credits depending on how much electricity they can provide in periods of high demand and/or low supply.[43] The battery's capacity and duration will determine the amount of capacity credits it can be allocated.[44]

The balancing market, ESS and capacity credit prices provide investment signals in the WEM. The preliminary modelling conducted by the ERA and its consultant assessed these revenue streams for batteries participating in the first three-year period after the expected commencement of the WEM reforms on 1 October 2023.

The energy and ESS price outputs from the ERA's market simulation model provided the inputs for modelling battery storage participation in these markets. FTI consulting developed a model that emulated the operation of battery storage in the WEM. This model was then used to inform the ERA's modelling of battery storage in PLEXOS and as a benchmark for assessing the modelling outcomes for battery storage in PLEXOS.

The model outcomes are summarised in this section with details in the consultant's report at Appendix 8. Details of the ERA's modelling are in Appendix 5.

Efficient commercial investment in battery storage in the WEM is challenging as:

40 Government of Western Australia media statement, 14 June 2022, 'State-owned coal power stations to be retired by 2030', (online) [accessed 14 June 2022]

41 Merredin Energy was the last gas plant to join the WEM in 2012 – Merredin Energy, 'Merredin Energy', (online) [accessed 1 July 2022].

42 The method for determining the capacity credit allocations is performed by AEMO following Wholesale Electricity Market Rules (WA), 1 July 2022, section 4.11. For battery storage, rule 4.11.3 assesses a battery's capacity credits based on how much electricity the battery can supply over four hours.

43 AEMO currently requires a battery's electricity from 4:30 pm to 8:30 pm each day which generally coincides with the day's peak demand. AEMO can amend this time window – Australian Energy Market Operator, '2022 Reserve Capacity Information Pack', (online) [accessed 28 June 2022]. This assumes that there is no reduction in capacity credits due to the application of the Network Access Quantity regime which reduces capacity credits for new electricity resources built in congested parts of the network.

44 A battery storage facility might also provide other system support services such as network support service through bilateral contracts with the network operator.

- Uncertainty in revenue streams is an impediment to financing battery storage projects.
- Competition from new entrant battery storage will quickly erode revenues for existing batteries in the WEM's small markets.

These are discussed below.

4.2.1 Battery investment considerations

Investors have indicated their intention to build large scale battery storage in the WEM and the National Electricity Market (NEM).[45,46]

Investment in battery storage is commercially viable when the facility achieves revenue sufficiency; that is, revenue from participating in the WEM is sufficient to provide a return on investment and cover operational costs over the asset's life. In the development of a large-scale battery, there is initially a high capital cost, but there are relatively low maintenance and operational costs over the life of the battery. An advantage of battery storage is that it can be constructed in a relatively short period of time when compared to traditional large scale power plants.[47] This allows a battery to start earning revenue sooner, given its shorter construction time.

Revenue is earned over the life of an asset, regardless of the type of technology, which makes forecasting future revenues critical to investment assessment. However, uncertainty over future revenues and costs increases investment risk, resulting in investors requiring a higher level of compensation.

The costs of installing large scale battery storage are expected to decrease as battery storage technology matures (see section 4.3.1 and Figure 7). Investors must compare the benefits of expected falls in installation costs with the benefits of being an early entrant to the WEM. Additional uncertainty is created by the short-term supply chain disruptions, due to the recent global pandemic, temporarily increasing the cost to develop large-scale battery storage.

4.2.2 Uncertainty in revenue in energy and ESS markets

The preliminary modelling shows that revenues for batteries are highly uncertain. The modelling demonstrates that the revenues from the ESS and balancing markets greatly decrease as more battery storage capacity enters the market. This indicates that the revenue opportunities from these markets are shallow, and the entry of a few competitors greatly affects expected forecast revenues. Importantly, ESS markets are a significant revenue source for batteries. However as more battery storage capacity enters the market, the revenue greatly diminishes.

Figure 5 depicts the expected average monthly revenue for a 100 MW/200 MWh (two-hour duration) battery storage facility operating in the balancing and ESS markets in the WEM for

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45 Examples of new large-scale battery developments include the Victorian big battery (300MW/450MWh) which is expected from 2022, and the Wandoan South battery in Queensland (100MW/150MWh) and the Wallgrove Grid Battery (50MW/75MWh) in New South Wales, which were completed in 2021. See: Consolidated list of Australian large scale battery projects: Goldsmith M, 2021, 'Australia's big battery boom', (online) [accessed 10 June 2022].

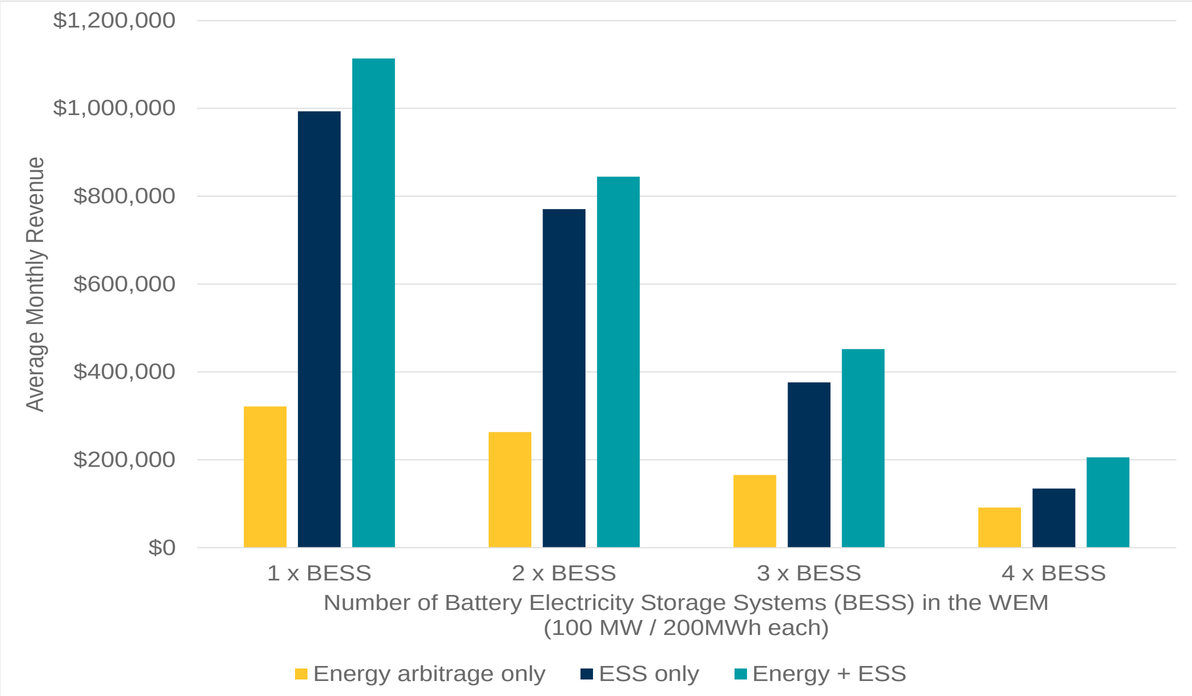
46 Alinta Energy, Neoen and Synergy have also recently announced their intentions to build large-scale batteries in the WEM. See: Alinta Energy, 2018, Alinta Energy switches on big Pilbara battery, (online). Muchea Battery, 2022, About the battery, (online). Synergy, 2021, Big Battery Project, (online).

47 For example, the Hornsdale Power Reserve was completed within 100 days from the date that the contract was signed with the South Australian Government – Project Management Institute, 1 October 2019, 'Hornsdale Power Reserve', (online) [accessed 22 July 2022].

the three-year period after the commencement of the reformed market.[48] Preliminary results show that additional, similar sized batteries entering the market decrease the first battery operator's monthly average revenue from $1.1 million to around $0.2 million.[49]

Figure 5 also indicates that ESS markets are expected to provide the bulk of a battery storage's revenue. Battery storage operators will favour revenue from ESS markets, because they are rewarded for availability, without always having to dispatch energy. This reduces battery degradation due to regular cycling. However, the ESS markets in the WEM are relatively small, such that first movers have an advantage as they capture the most lucrative revenue streams and possibly erode value for other future battery storage projects.

Figure 5: Average monthly revenue for battery storage



Source: ERA's analysis of FTI Consulting's battery revenue optimisation model and ERA's PLEXOS modelling.

The energy arbitrage for battery storage requires large differences between the prices to charge and discharge for it to be profitable. The modelling results show that battery storage is unlikely to make significant returns from energy arbitrage due to the costs associated with cycling the battery storage system and assumed relatively low-price spreads in the WEM.

The addition of more renewable energy into the market further increases revenue uncertainty for battery. Although increased renewable energy generation increases demand for ESS, it helps to reduce price swings as renewable generation bids in at a very low price due to its low variable cost to produce electricity. Similarly, more batteries in the market increases competition as all batteries compete to dispatch during the evening demand peak, putting downward pressure on prices. As more battery storage facilities seek to charge during periods of low demand, prices during off-peak periods are likely to increase. Additional entry of renewables and battery storage can reduce the price volatility and revenue expectations, creating greater uncertainty for balancing market revenues.

48 The ESS revenue modelled in this discussion paper does not include the proposed Rate of Change of Frequency (RoCoF) ESS market as this modelling by the ERA is under development. The final WEM report will include RoCoF ESS modelling forecasts.

49 Based on a battery optimising over both ESS and energy arbitrage revenue.

There is also a high level of uncertainty surrounding the forecasting of ESS market prices, particularly in the reformed market where ESS prices will be set using a new method based on co-optimisation with energy-only market prices. This uncertainty creates the risk that battery operators may be unable to recover their capital costs, which can be a barrier to investing in battery storage facilities.

4.2.3 Uncertainty in capacity revenue

Battery storage investors will participate in the RCM if they consider it commercially viable. As part of the energy transformation, there is currently some uncertainty about potential changes in the reference technology used to price capacity and other elements of the RCM, such as reserve capacity obligations, non-compliance charges and capacity valuation methods.

For example, there is uncertainty about the total amount of capacity available in the system and the associated capacity price. The State Government has announced that no new gas power plants will be constructed after 2030; however, the current benchmark plant used for setting the capacity credit price is a 160 MW liquid-fuelled gas generator.[50] Stakeholders have previously raised the concern that the current benchmark facility for setting the capacity credit price is outdated and is unlikely to be a suitable choice for investment in the WEM.[51]

Additional uncertainty for batteries occurs where:

- The capacity contribution of battery storage facilities and hence, their capacity revenue, can vary over time as the periods with the highest likelihood of loss of load change with the change in the supply mix. The amount of capacity credits provided to batteries depends on how large the capacity credit obligation window is (currently four hours), which reflects the window of time during which the likelihood of loss of load is high. If this window increases in size (for instance, to a longer window of five hours), as recently indicated through the review of the RCM, this will then decrease the amount of capacity credits that a battery will receive.[52] In comparison, the capacity contribution of thermal generators does not vary with changes in the profile of system reliability risk periods.
- If a battery is installed into a congested part of the network, the Network Access Quantity (NAQ) regime will also restrict the amount of capacity credits it will receive.[53] Once the reformed WEM commences, more information will be available on how much NAQ will be available for new entrants to the market.
- The method used to evaluate the capacity value of battery storage facilities may need to be amended to incentivise longer duration batteries to be installed in the WEM. The current four-hour window reflects the period over which the WEM is most likely to face reliability risk. As thermal plants retire and more renewable energy enters the grid, system reliability risk can be prolonged. Longer duration batteries can provide a higher level of contribution to system reliability as the high reliability risk window of time increases.

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50 Government of Western Australia media statement, 14 June 2022, 'State-owned coal power stations to be retired by 2030', (online) [accessed 14 June 2022]. The BRCP reference generator is defined in the Market Procedure: Benchmark Reserve Capacity Price (WA), 9 November 2020.

51 Merredin Energy, 2018, Submission to Draft Report: 2019 Benchmark Reserve Capacity Price for the 2021-22 Capacity Year, p. 1.

52 This is because the battery has only a limited amount of capacity that would need to be spread over a longer period.

53 The WEM's mechanism for managing the effect of congestion on system reliability is the Network Access Quantities framework, which rations investment and provides a disincentive to locate new facilities in congested parts of the network.

On the upside, the retirement of existing thermal generators will free up capacity in the network, allowing new entrants to provide energy and ESS. Knowledge of the retirement date of certain generators can assist in assessing the expected capacity credits and capacity price that a battery could receive.

4.2.4 Uncertainty in charging for network use

There is also uncertainty in the WEM about how batteries will be charged for network use. Currently, a generator pays network charges to supply electricity to the SWIS and loads pay a network charge to use power from the SWIS. For comparison, battery storage in the NEM may pay both generation and load transmission costs.[54] Western Power is currently seeking stakeholder feedback on developing a network tariff for transmission connected storage, which may inform how batteries will be charged for network use in the WEM.[55]

4.3 Possible measures for ensuring revenue sufficiency

Sections 4.1 and 3.2 explained that the WEM will likely undervalue the services provided by battery storage and renewable generation. The ERA has considered how revenue sufficiency may be achieved to facilitate participation by storage and renewables in the WEM. This section provides a high-level overview of possible measures to address a lack of revenue sufficiency for storage and renewable generation.

Efficient pricing for services and investment in renewable generation and storage facilities can be promoted by appropriately valuing the contribution of these facilities through:

- introducing a capacity procurement mechanism that will incentivise the entry of flexible capacity to provide flexibility services.
- reviewing the existing methods for estimating the contribution of facilities to system adequacy and the benchmark facility for the pricing of capacity credits.
- accounting for revenue and cost uncertainty and expected changes in technology costs. These options are considered in section 4.3.1.

Further government initiatives may be required to fill any residual revenue gap.

The implementation of one or a combination of the possible measures may provide more certainty that investment in new storage and renewable generation will receive sufficient revenue to cover costs. It will also reflect the value of these facilities to the WEM and to the State's economy-wide decarbonisation goals.

4.3.1 Efficient pricing for services and investment

This section explores measures to efficiently price services required by the WEM, to mitigate the under-compensation of renewable generation and storage facilities and allow service providers to recover their costs.

54 AEMO's recommendation to the AEMC's rule change on integrating energy storage systems into the NEM was to exempt storage from network charges when charging – Carol, D. 2 December 2021, 'Charges unchanged as AEMC reveals final rule for batteries', PV magazine, (online) [accessed 1 July 2022], and Australian Energy Market Commission, 2 December 2021, 'Rule Determination – National Electricity Amendment (Integrating Energy Storage Systems into the NEM) Rule 2021' (online) [accessed 1 July 2022]. This part of the rule change was not adopted.

55 Western Power, 2022, Access arrangement information for the AA5 period - Additional Information - Tariff structures and reference services, p. 11, (online) [accessed 1 July 2022].

Battery storage and renewable generation provide a range of services and positive externalities that are not currently priced by the WEM. Introducing an efficient market price that recognises the value of battery services, such as fast frequency response, transmission congestion relief and simulated inertia, allows investors to be remunerated for the benefits that their facilities provide to the market.

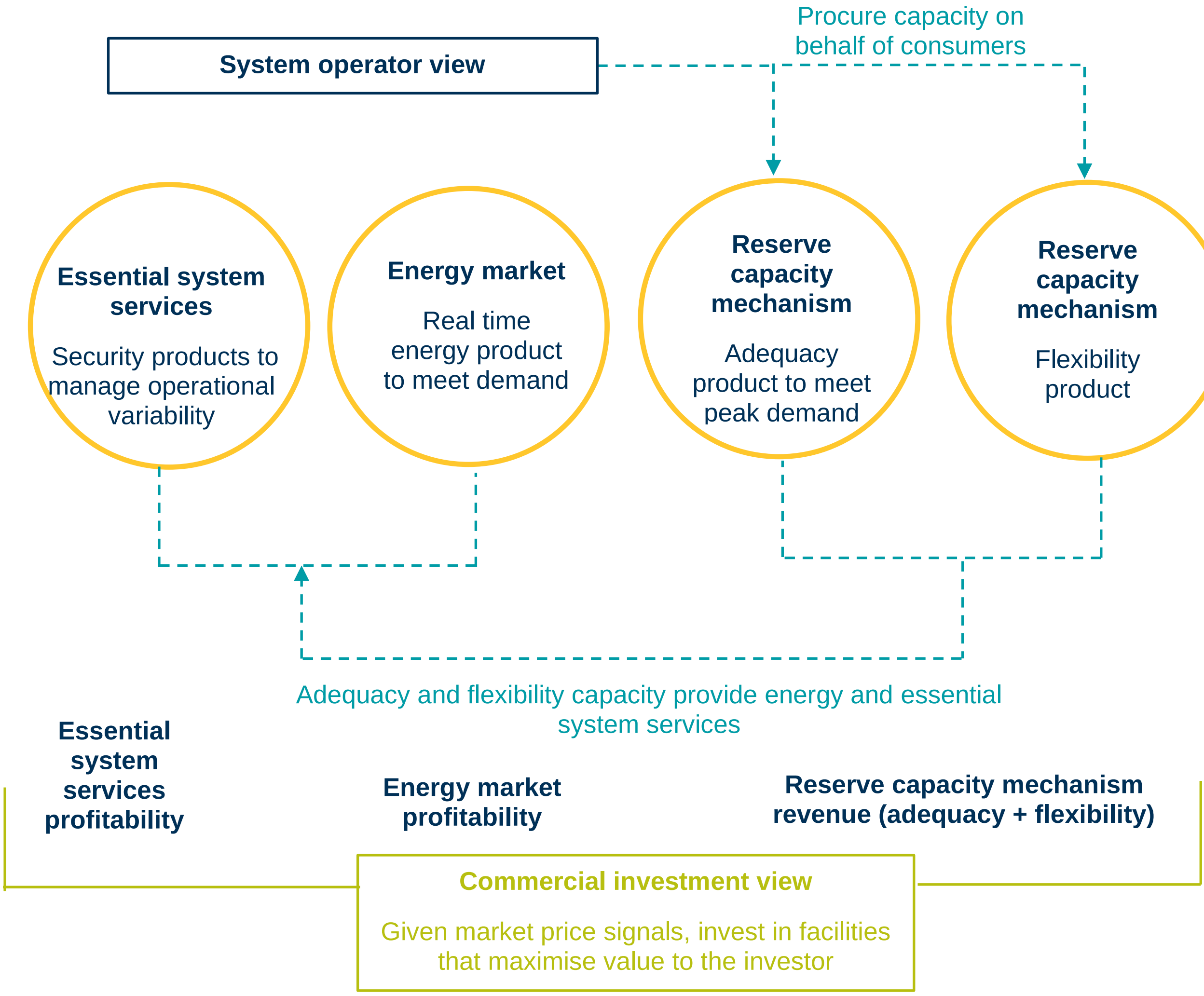
The commercial viability of new investment and their contribution to reliability in the SWIS may also require further development of market structures and incentive mechanisms. An example of how the State Government is addressing this is through its review of the RCM. The RCM review is considering introducing a flexible capacity procurement mechanism to incentivise the entry of flexible capacity to provide flexibility services.[56]

As more renewable generation and distributed energy resources enter the system, the existing design of the RCM might not be adequate to ensure resources with fast responses are available to arrest sudden increases or decreases in supply and demand. This is because the price signal for the adequacy capacity product does not account for the ability of the capacity procured to control short-term variations in supply and demand (see section 4.2). If a flexibility capacity mechanism is developed, battery storage is expected to receive revenue for this purpose from that mechanism.

Figure 6 depicts the main price signals in the market after the inclusion of a flexibility capacity product. There might be overlaps between the current capacity product, which provides for system adequacy to meet peak demand, and ramping flexibility capacity, and so care is needed to avoid double counting capacity payments. For example, in the future when the supply of the adequacy capacity product is well in excess of what the system needs to meet peak demand, the adequacy product price should decrease to discourage additional entry to provide the adequacy capacity product. Despite an excess of capacity products, the flexibility capacity product price must increase to drive investment in flexibility capacity if the system requires additional flexibility.

[56] Energy Policy Western Australia, 2022, Reserve Capacity Mechanism Review Working Group, (online).

Figure 6: Price signals in the WEM after including flexibility capacity product



In line with the WEM objective to minimise costs to consumers, the administered prices need to suitably reflect the outcomes of competitive auctions for the procurement of adequacy and flexibility products. For example, the payment to a marginal new entrant for either adequacy or flexibility capacity needs to be just sufficient to encourage their entry to the market, having consideration for expected revenues from participating in energy and ESS markets and the RCM's capacity products.

The RCM uses a benchmark facility as a reference of what the most efficient cost is for extra capacity to enter the SWIS. The current pricing of capacity credits is based on recovery of fixed costs of the benchmark facility – which is just sufficient to encourage the entry of the benchmark facility to the market. This pricing approach will need to be reviewed when the benchmark facility is changed to a different technology, to ensure the price is sufficient to encourage entry.

The current pricing of capacity credits in the WEM is based on a soon to be outdated benchmark technology. This may result in inefficient price signals for the entry of flexible generation and storage facilities that are required to maintain supply reliability at the lowest cost possible. When compared to the existing benchmark facility for capacity adequacy, battery storage facilities face greater uncertainty about future revenues and costs, as explained in section 4.2. In the past, the revenue stream for the benchmark plant was mainly through the sale of capacity credits and was relatively predictable. For a new technology, such as battery storage, the investment case is reliant on forecasting energy, ESS, and capacity revenue streams that, going forward, are expected to be variable and largely unpredictable.

The ERA compared the commercial feasibility of large-scale battery investment with the current benchmark gas turbine used for the pricing of capacity credits in the WEM.[57]

Drawing this comparison demonstrates how changes to capacity credit prices may change the feasibility of investment in battery storage facilities.[58] The results indicate that large-scale battery storage facilities (or when combined with solar or wind generation) may be suitable candidates to set the price of capacity credits in the SWIS as their development costs are expected to decrease. Figure 7 shows the expected BRCP over the next 15 years based on the current benchmark open-cycle gas turbine (OCGT) facility and a 100 MW/200 MWh battery storage facility.[59]

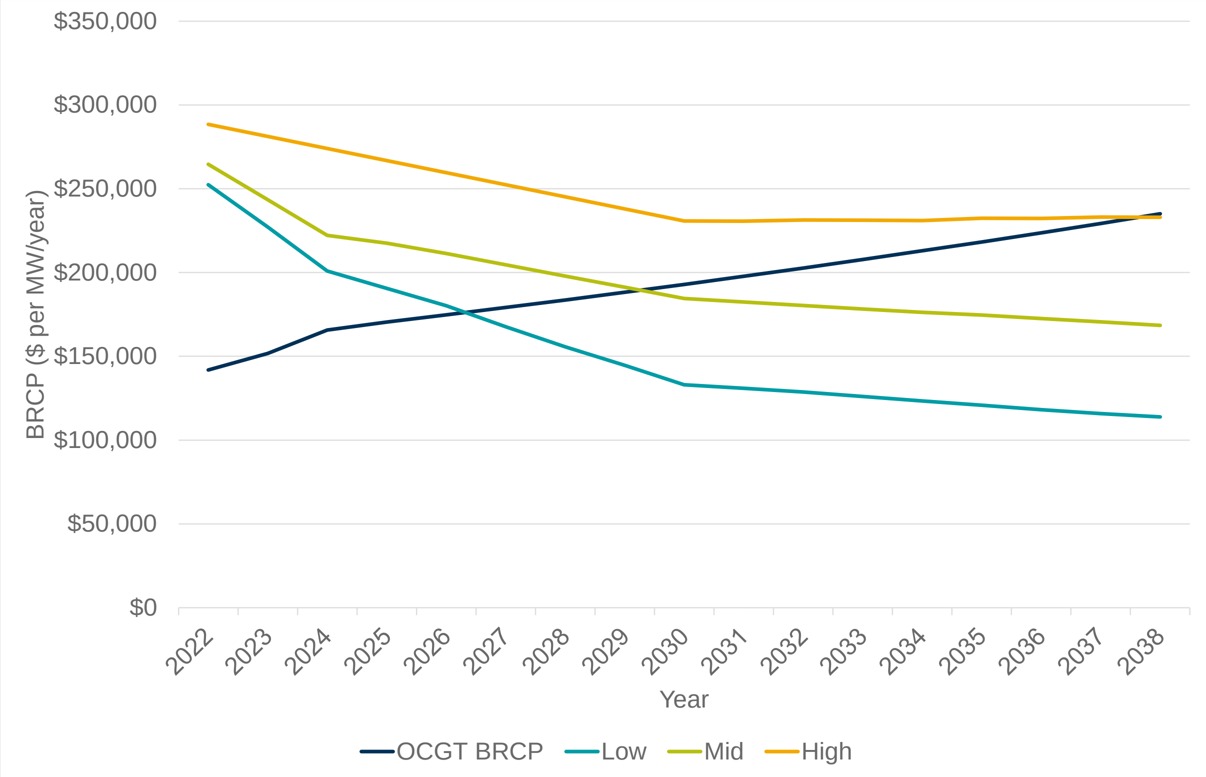
As demonstrated in Figure 7, the BRCP based on battery storage falls below the BRCP based on the current benchmark facility after 2029. This suggests that the fixed investment and operating costs over the life of a battery are expected to fall below that of the current benchmark facility. This may make battery storage a candidate to be the reference facility in the future.

57 Capacity credits provide a source of revenue depending on the capacity an electricity resource can provide to the SWIS. The price of capacity credits depends on the excess capacity in the system relative to the minimum reliability requirements (stated in Wholesale Electricity Market Rules (WA), 1 July 2022, Rule 4.5.9).

58 Details of the battery investment feasibility model is detailed in Appendix 1. The battery assessed is a stand-alone battery which is not combined with another energy source, for example, a wind farm.

59 The BRCP liquid-fuelled open cycle gas turbine is assessed using the current method for the calculation of BRCP (see Market Procedure: Benchmark Reserve Capacity Price (WA), 9 November 2020). From the last BRCP determination for the 2024/25, that BRCP OCGT price is indexed to an expected inflation rate.

Figure 7: Estimated capacity revenue required (BRCP) for a 100 MW/200 MWh battery storage ($AUD) compared to a 160 MW liquid-fuelled OCGT (the current benchmark plant for determining BRCP)



Source: ERA analysis of National Renewable Energy Laboratories data and estimated BRCP adjusted by expected inflation.[60]

Note: The BRCP based on battery storage facility is estimated based on three possible scenarios of development costs in the future: low-, mid-, and high-cost scenarios. These different cost scenarios are based on an assessment of publications regarding installing large-scale battery storage.[61]

The method in the WEM Rules to calculate the BRCP does not account for possible profit margins from participating in the energy and ESS markets. It also does not account for the expectation of the BRCP's reference generator's costs decreasing or increasing in future periods. Battery investors would be deterred from entering the market if they expect the BRCP to decrease in future periods, as they would not receive capacity credit revenue based on the higher BRCP determined in the earlier period, and therefore may be unable recover the costs of their investment.

For example, as shown in Figure 7, the BRCP in 2022 is $141,900/MW/year, however, this level of capacity price might not be sufficient to encourage the entry of battery storage to the market in 2022. This is because battery storage investors would expect the BRCP to decline over future periods, as the BRCP falls as battery technology costs decrease, if battery storage became the BRCP's reference technology. Without accounting for this, the BRCP may be under-priced from what is required to attract new capacity (including battery storage) to join the WEM.

60 National Renewable Energy Laboratory (NREL), 2021, Cost Projections for Utility-Scale Battery Storage: 2021 Update, p. 9. NREL data has been converted into Australian Dollars.

61 Method described in National Renewable Energy Laboratory, 2021, Cost Projections for Utility-Scale Battery Storage: 2021 Update, pp. 1-4.

Internationally, the Pennsylvania New Jersey Maryland Interconnection (PJM) made a similar finding when assessing candidate reference technologies (gas turbines and large-scale battery storage) for their capacity pricing system.[62] In its fifth review of the net cost of new entry to its market, PJM assessed battery storage as a source of capacity due to some areas having environmental restrictions that limit or preclude the development of fossil fuel plants.[63] Draft results published by PJM estimated that the net cost of new entry for a battery system would be significantly higher than for a natural gas-fired plant.[64]

As in the WEM, one of the drivers of the battery system's high cost of entry is the uncertainty in ESS revenue. Most of a battery's expected revenue is expected to come from ESS (see Appendix 6); however, similar to preliminary modelling results from the WEM, PJM forecasted that this revenue source would quickly decrease as more batteries connect to the system.

Batteries can also provide multiple benefits to the surrounding network area, including by reducing the risk of curtailment and alleviating pressure on network infrastructure (see Appendix 5 for details). This is recognised under the proposals for non-co-optimised ESS.[65] Despite these broader benefits there is currently no ability for one project to 'charge' another project for the benefits provided to them. This 'charge' could be solicited through a compensatory mechanism.

Alternatively, energy storage could be added to the portfolio of traditional transmission solutions when the driver for the investment is to relieve transmission congestion. Markets centred around congestion relief are likely to incentivise batteries to be operated to mimic the effects of traditional solutions (such as transmission construction) to alleviate congestion.

Questions

1. What other investment support mechanisms might be needed to support investment in large-scale renewable generation and battery storage?

2. What changes might be needed for the pricing of capacity credits in the SWIS? For example, what framework is to be used for determining the reference technology for setting the price of capacity credits?

[62] Pennsylvania, New Jersey, Maryland (PJM), 25 March 2022, 'Fifth Review of the Net CONE Draft Results', (online) [accessed 1 July 2022].

[63] The cost of new entry in the PJM market is the total annual net revenue (net of variable operating costs) that a new generation resource requires to recover its capital investment and fixed costs, based on reasonable expectations of future cost recovery over the resource's economic life. The net cost of new entry represents the first-year revenues that the new resource would need to earn in the capacity market after netting out energy and ancillary service margins from the cost of new entry. Brattle Group, 2018, PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date (online) [accessed 21 July 2022].

[64] Ibid, p. 22.

[65] Energy Policy Western Australia, 2021, Framework for Non-Co-optimised Essential System Services, (online) [accessed 24 June 2022].

5. Other considerations for a transitioning market

This section considers market mechanisms that affect the pricing signals encouraging long-term investment in renewables and battery storage technology. The State Government's review ahead of new market commencement in October 2023 is expected to consider amendments to some of these mechanisms.

5.1 How will battery storage bid into the WEM?

Storage technologies like large-scale batteries can offer supply to the energy market at prices that reflect its costs (short run marginal cost; SRMC). Battery storage facilities participate in the market differently to both renewable and thermal generation as the battery can store electricity when prices are low and sell this back to the market when prices increase. The challenges that this participation may raise for market power mitigation is addressed in in Appendix 6.

Internationally, work has been undertaken to develop mechanisms which aim to ensure that battery storage participates competitively in existing day ahead, real-time, ESS and capacity markets, for the benefit of consumers. For example, North American jurisdictions use structural tests (e.g., the three pivotal supplier test) or 'conduct and impact' tests to determine the presence of market power or the exercise of market power, respectively, and if detected, the resource offer is mitigated to the battery's reference price or SRMC.

Accordingly, much thought has already been invested into the calculation of SRMC for various battery storage systems. Appendix 6 provides an overview of these developments in other jurisdictions.

Just as the SRMC of conventional generation depends on the opportunity cost of using fuel for electricity generation, the SRMC of battery storage depends on the opportunity cost of stored energy, which is the best alternative for dispatching energy and receiving the current energy or ESS prices. The battery operator's expectation of future energy and ESS market prices will determine the SRMC of battery storage. This is because the battery operator will have the opportunity to use the energy stored for dispatch in later periods when energy or ESS prices are expected to be higher.

However, calculating the SRMC of batteries is somewhat more complicated, in practice, than determining the SRMC of conventional generation, as the battery's SRMC also depends on the current state of charge.[66]

The SRMC of dispatching one more unit of energy can be estimated using the following principle. At a point in time, and with a certain state of charge, a battery operator has three operation actions: charge, discharge or take no action (subject to technical and market obligations). The battery storage operator forecasts upcoming energy and ESS prices and determines the optimal operational action that it expects to maximise its profit. The SRMC of the battery of dispatching one more unit (or any level of output above or below) than the optimal operational action is the decrease in expected profit from moving away from the optimal operational action.

[66] As discussed in Appendix 6, the cost for a battery to cycle (move from one state of charge to another) is non-linear in nature and difficult to model as it may increase with the total depth of discharge of the resource, and can be technology (or chemistry) dependent.

The work program currently underway by EPWA is considering how offers to market are defined in the new WEM.

5.2 Locational pricing differentials

The WEM's single market clearing price means that all market participants face the same price regardless of the variation between locations of demand for electricity or the cost of supply. When consumption and production decisions are not informed by the real cost of supply, it can lead to higher costs across the network and an increase in the long-term supply cost of electricity to consumers.

In other jurisdictions, nodal pricing allows the price of electricity for each node to clear at a price that reflects the value of electricity in that location. Nodal pricing can provide economically efficient locational price signals for the supply and demand of electricity, reducing under and over supply and consumption from the economically efficient level. By capturing the costs of congestion, generation and transmission and losses in real time, nodal, or locational marginal pricing, supports efficient investment and electricity purchasing decisions. However, locational marginal pricing can add complexity and uncertainty to investment decisions and increase the volatility of prices.

The ERA's preliminary analysis shows that variations in the supply cost of electricity to different parts of the network are currently masked by single-node pricing.[67] One cost that is reflected in the pricing differentials is congestion. When parts of the network get congested, the effective cost of supply increases. In the WEM, consumers would not be aware that they are supplied by a congested part of the network and would not moderate their demand to reflect the higher cost of supply.

5.2.1 Alternatives to improve efficiency in the WEM

Locational marginal pricing may increase economic efficiency in the WEM by informing decisions to invest, supply and consume. However, it is not clear that the benefit of increased efficiency would outweigh the costs of uncertainty and complexity, particularly in the early years of the new market. Through the State Government's energy market reforms, the WEM has measures to improve both the efficiency of investment decisions and congestion management, without implementing locational marginal pricing.

The WOSP provides a means to improve the efficiency of investment decisions in the WEM by indicating where and when investment in transmission and generation facilities will be required. For simplicity, the first WOSP was based on single node modelling. If the second WOSP considers the pricing differentials between the nodes and apportions cost, the optimal priority projects can be identified for the relevant locations.

The WEM's mechanism for managing the effect of congestion on system reliability is the Network Access Quantities framework, which rations investment and provides a disincentive to locate new facilities in congested parts of the network. In the reformed energy market, real-time congestion management will be provided through security constrained economic dispatch, which automatically includes network and security constraints to ensure system security is maintained at the lowest possible cost. Given these measures, it is not clear if additional locational energy prices would improve the efficiency of investment and supply decisions that are guided by existing locational incentives.

67 See Appendix 70 for Endgame Economics' chart on volume weighted average price by zone.

Questions

3. What benefits would locational marginal pricing bring to the WEM and how could the uncertainty and price volatility of locational marginal pricing be managed?

Appendix 1 List of Figures

Appendix 2 List of Tables

Appendix 3 Questions to guide stakeholder feedback

This appendix lists the questions presented throughout the paper to guide stakeholder feedback.

The ERA also welcomes feedback on any other matters relevant to this review.

Questions

1. What other investment support mechanisms might be needed to support investment in large-scale renewable generation and battery storage?

2. What changes might be needed to the pricing of capacity credits in the SWIS? For example, what framework is to be used for determining the reference technology for setting the price of capacity credits?

3. What benefits would locational marginal pricing bring to the WEM and how could the costs of locational marginal pricing – uncertainty and price volatility – be managed?

Appendix 4 Relevant legislation

Excerpts from the *Electricity Industry Act 2004* that are relevant for the ERA's triennial WEM review are provided below.

122. Regulations for a wholesale electricity market

2. The objectives of the market are —

   a. to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system; and

   b. to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors; and

   c. to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions; and

   d. to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and

   e. to encourage the taking of measures to manage the amount of electricity used and when it is used.

128. Review of market operation

1. The Authority is to review the operation of the market as soon as practicable after the expiration of 3 years from the commencement of this Part and thereafter as soon as practicable after the expiration of 3 years from a report being laid before each House of Parliament under subsection (5)(a).

2. The purpose of the review is to assess the extent to which the objectives set out in section 122(2) have been or are being achieved.

3. Not later than 3 years and 6 months after the commencement of this Part, or after the last preceding report was laid before each House of Parliament under subsection (5)(a), as the case may be, the Authority is to give the Minister a written report based on the review.

4. If the Authority considers that some or all of the objectives set out in section 122(2) have not been and are not being achieved, the report is to set out recommendations as to how those objectives can be achieved.

5. As soon as practicable after receiving the report, the Minister is to —

   a. cause the report to be laid before each House of Parliament; and

   b. prepare a response to the report and cause the response to be laid before each House of Parliament.

6. As soon as practicable after the report is laid before each House of Parliament, the Authority is to post a copy of the report on a website maintained by the Authority.

[Section 128 amended: No. 9 of 2020 s. 22.]

129. Public consultation

1. In the course of conducting a review under section 128(1), the Authority is to seek public comment on the extent to which the objectives set out in section 122(2) have been or are being achieved (the issue).

2. The Authority is to cause a notice giving a general description of the issue to be —

   a. published in a daily newspaper circulating throughout the State; and

   b. posted on a website maintained by the Authority.

3. The notice is to include —

   a. A statement that any person may, within a specified period, make written submissions on the issue to the Authority; and

   b. the address (including an email address) to which the submissions may be delivered or sent.

4. The period specified under subsection (3)(a) is not to end less than 30 days after the day on which the notice is published under subsection (2)(a).

5. The Authority is to have regard to any submission made in accordance with the notice.

[Section 129 amended: No. 9 of 2020 s. 23.]

Appendix 5 ERA modelling

The ERA used its PLEXOS model of the WEM to inform a battery storage investment feasibility model and assess the effectiveness of the WEM's pricing signals.

The underlying methods and assumptions for both models are provided in this appendix.

ERA's model of the Wholesale Electricity Market

Model configuration

The ERA's PLEXOS WEM model has been configured to co-optimise electricity generation with essential system services (ESS).[68] The model is configured to identify the least cost means of meeting the energy and the defined ESS requirements in the WEM. It forecasts dispatch and pricing outcomes for the capacity years from October 2023 to October 2026, the first three years of the WEM after implementation of the State Government reforms.

The model draws from a database that describes the physical characteristics and associated costs and operational constraints for generators and battery storage facilities that are expected to connect to the South West Interconnected System (SWIS).

There are no batteries operating in the WEM as of July 2022, however the model assumes that four batteries will enter the market prior to or during the modelling period (from October 2023 to October 2026). There is uncertainty around the dispatch and participation of the batteries in the market.

The ERA's PLEXOS model used a simple representation of the Generator Interim Access (GIA) constraints, when the modelling was undertaken for this discussion paper. For the final report, the modelling will include a detailed network constraint setting to better emulate the outcomes in the WEM after the implementation of the reforms. It will also include the new ESS reserve Rate of Change of Frequency (RoCoF) service which will provide synchronous or synthetic inertia to slow down the rate of change of electrical frequency on the power system.

Market configuration

The ERA's PLEXOS WEM database includes an energy market and four 'reserve' services for modelling spinning reserve, load rejection reserve, and both upwards and downwards load following ancillary services (LFAS). Ready reserve is applied as a scheduling constraint in the model, requiring a scheduled generator, a battery or demand side capacity available within fifteen minutes notice to cover 30 per cent of the largest contingency output from a single unit (largest generator operating in the WEM and ten per cent of the estimated output from rooftop solar generation).

The model is configured on 30-minute trading intervals, with the trading day starting at 8:00 AM, and uses a 24-hour look-ahead functionality.

[68] Ready reserve is the ancillary service (essential system service) for fast-start generators to be available within fifteen minutes to cover 30 per cent of the total output of the generator with the highest total output synchronised to the SWIS.

The WEM, after the implementation of the State Government's reforms, is expected to run in 5-minute dispatch intervals. However, the model is configured on 30-minute trading intervals, as current input data is available in 30-minute steps only.

Essential system services requirements

While the model forecasts market outcomes in the WEM following the completion of the State Government's reforms, there are material constraints on the modelling inputs, as the new market design is still under development. Many market parameters are still unknown and some of the modelling settings reflect the current market's settings. This is recognised as a shortcoming of the modelling.

The ERA's model uses ESS requirements that currently apply in the WEM, as information on the ESS requirements beyond 1 October 2023 are not known.

- Spinning reserve contingency (contingency reserve raise): the spinning reserve 'risk', or contingency, is the larger of 70 per cent of the largest output from a single generator or the 'North Country contingency'.[69] There is an additional contingency, which AEMO applies related to the loss of rooftop solar generation, which is equivalent to ten per cent of the output of all rooftop solar systems installed.[70]
- Load rejection reserve requirement (contingency reserve lower): the requirement is assumed to be 90 MW in the planning horizon in advance of the trading interval when the generating units providing the reserve are committed.

In the model, generators and batteries were limited to provide no more than 30 per cent of the spinning reserve and load rejection contingency quantity to reflect the need to spread risk across multiple generators and prevent the model selecting a single facility as the source for all ancillary services (essential system services).[71] Two contracts for spinning reserve were assumed to be in place for the duration of the forecast period, with a combined capacity of 63MW.

- Upward and downward load following ancillary services (regulation raise and lower) requirements: these requirements were set at 110 MW for daylight hours (5:30AM to 7:30PM) and at 65 MW overnight.

The WEM Rules will require that a megawatt offered into the market can be allocated for a single use only, either to provide energy, or to provide one essential system service at any time. This means that there cannot be an overlap between the downward and upward contingency and regulation reserves, and these services were modelled to be mutually exclusive in the ERA's model.

The ERA's model introduced an ESS enablement duration. This setting was included to restrict battery participation in the ESS markets to quantities that align with their technical parameters. The current market parameters require contingency reserve raise to be sustained for 15 minutes and contingency reserve lower for 60 minutes. The model set a 30-minute ESS requirement for all four ESS services for modelling simplicity.[72] The ERA recognises that

69 The North Country Contingency is the combined output of Yandin, Warradarge, Beros Road, and Badgingarra wind farms connected in the same part of the network.

70 AEMO stated that this number can vary, but the ERA has adopted a 10 per cent contingency for simplicity.

71 AEMO advised that this is an operational practice and that 30 per cent is not always fixed for all facilities. The restriction is applied more dynamically based on the system conditions and available facilities. The ERA has applied fixed 30 per cent across all trading intervals and facilities for simplicity.

72 This setting will be adjusted to reflect the requirements better for the final report.

following implementation of the State Government's reforms, the ESS parameters are likely to be different.

Network configuration

The network is assumed to be unconstrained, but with specific network constraints (such as applied under Generator Interim Access contracts) separately modelled based on the observed application of the constraint tool developed by Western Power.

The application of the Generator Interim Access constraint was modelled in steps, partially with some pre-processing outside of PLEXOS. The unconstrained half-hourly generation for non-scheduled generators connected under the constrained access contracts was estimated outside PLEXOS. This provided a base output profile to which the constraints, driven by scheduling decisions for scheduled generators connected in those parts of the network in combination with the amount of unconstrained non-scheduled generators in each trading interval, were applied.

Electricity demand

There was no half-hourly demand forecast available for the modelling period. The ERA took the last three full years' demand profiles (from October 2018 to October 2021) and added back AEMO's estimated rooftop solar output to derive an underlying demand figure and profile. This was scaled to align with AEMO's expected forecast peak demand, minimum demand and operational consumption indicated in the 2021 Electricity Statement of Opportunities (ESOO).[73,74]

Rooftop solar electricity generation was estimated using stochastic output data derived from the distributed rooftop solar output data provided by AEMO, within sunrise and sunset periods, available from Geoscience Australia.[75] This was escalated monthly through the forecast period to account for new installations expected to connect during the forecast period. New installations were assumed to have the same generation characteristics as existing installations. The rooftop PV output profile was then deducted from the scaled forecast underlying demand to derive an operational demand used in the forecast period. Conceptually, this approach was like that used by AEMO for its ESOO forecast.

The forecast model included a demand constraint that restricted the generation of any non-scheduled generation once demand fell below a certain level (for a trading interval). This constraint was included in anticipation of the expected operation of the system during low load events.[76]

Rooftop solar assumptions

For the base scenario, the same installation rate and capacity from the expected case from the ESOO were used.[77] The solar installation rates in terms of installed capacity and the

[73] Australian Energy Market Operator, 2021, *2021 Electricity Statement of Opportunities*, (online).

[74] For the final report the ERA will update forecasts with the Australian Energy Market Operator, 2022, *2022 Electricity Statement of Opportunities*, (online).

[75] Geoscience Australia, Geodetic Calculators, Perth location, (online).

[76] Australian Energy Market Operator, 2021, *2021 Electricity Statement of Opportunities,* (online).

[77] Ibid.

number of installations from the Clean Energy Regulator's postcode data for SWIS postcodes was also reviewed to ensure the assumption's currency.

Rooftop solar capacity and generation were estimated from postcode data reported by the Clean Energy Regulator and actual rooftop PV generation profiles, which were provided by AEMO. Growth in rooftop solar was forecast based on the last three capacity years' monthly installation rates aligned with AEMO's projected growth rates, extrapolated from linear and power trendlines of best fit, and relative growth rate calculations. The growth wedge accrued monthly. These forecasts were compared for consistency with AEMO's expected solar growth uptake.

Generator configuration

The ERA collected and verified the physical and operational characteristics for each generator in the SWIS and estimates for generators and facilities committed but not yet constructed. These include:

- fuel consumption rates (heat rates)
- operation and maintenance costs (load dependent and independent)
- generator commitment and decommitment costs
- fuel supply costs, daily, weekly, or monthly limits, take or pay quantities and over-run costs.

Market standing data was used to define:

- generator ramp rates
- minimum stable generation thresholds
- minimum time to synchronisation (cold, warm, and hot)
- minimum down time.

Other information items from the market surveillance data catalogue were used to define:

- forced outage rates
- generator loss factors.

Fuel input costs

Fuel input costs were collected from market participants and scrutinised to ensure consistency with the short run marginal cost principles in the WEM Rules and the opportunity cost of gas. Many generators' fuel input costs reflect spot market costs.

Heat rates

Heat rate is a measure of a generator's efficiency in converting fuel to electricity. It is the energy content of the fuel needed to produce a given output quantity. The heat rates determine the fuel-related operating cost of a generator. Marginal heat rates reflect the incremental change in fuel required to generate an additional unit of output. Thermal generators provided the ERA with their heat rate curves which were used to calculate marginal heat rates.

Bid-cost mark-ups

The marginal costs for the generators can be adjusted to account for actual or historical bidding behaviour through mark-ups.

The ERA PLEXOS model used for this discussion paper does not use bid-cost mark-ups, as the ERA assumes that generators will be dispatched based on their costs by the dispatch engine. Also, it is not known how generators will change their bidding behaviour after the implementation of the State Government's reforms.

Outages

Unplanned outages were modelled as a percentage of the unit's operating hours in a year and as a percentage of the total hours in a year through generator's forced outage rates. The forecast forced (unplanned) outages were derived from historical outage rates. Where a clear outage pattern could be discerned from historical data (such as a "sawtooth" outage pattern), this was used to determine the forced outage rate. The modelling also accounts for partial outages through generators' partial forced outage rates. These are applied randomly throughout the forecast period.

For new generators committed to commence generation in the market within the forecast period, the ERA used generic technology specific availability rates to set maintenance requirements. These target availability rates were tested directly with project proponents.

Wind and (grid connected) solar generator output

Variable generators' output is driven by resource availability. An output profile for generators is needed as an input to the model.

The ERA PLEXOS model used actual generation outputs for some of the grid connected renewable facilities, reprofiled where appropriate. New wind farms in the market have no or only limited operational data. For these wind farms, the ERA used the generation forecasts estimates that had already been prepared by independent, AEMO-accredited experts and provided by market participants for the capacity certification process.[78]

For generators connected under the Generator Interim Access contracts, several constraints have the possibility of limiting wind farm output in a single network region. The first constraint limited the total output of wind farms in the north country region. This was applied first to the forecast unconstrained output of the wind farm prior to input into the PLEXOS model. The second set of constraints depends on the combined output of the wind farms with other generators connected in the region. This constraint was applied dynamically within PLEXOS and was developed with guidance from AEMO and Western Power.

Generator operational constraints

In the forecast WEM model there are operational constraints to alter the behaviour or availability of generators. These constraints define specific operating rules or impose limits within the system and prevent unrealistic model outputs.

[78] These estimates are used in as inputs to the relevant level method for capacity allocation.

Constraints were also applied to limit the ESS quantities that any one facility can provide. These constraints impose an upper limit to the provision of up to 30 per cent of the spinning reserve and load rejection reserve risk per facility.

Renewable energy certificate prices

Where generators do not have a historical bidding profile upon which to base their offer curves into the electricity market, the modelled offers were based on their marginal cost including the forward value of renewable energy certificates (REC) over the outlook period. The nominal REC (large-scale green certificate) was derived from a two year forward contract price reported by Bloomberg for forward supply maturing in the years modelled.

Batteries

Four equally sized battery systems are included in the model to operate during the forecast period. All batteries have been configured in the model to be operating in the forecast window.

Sensitivity analysis

For the discussion paper, the ERA tested one scenario in addition to the base case, which tested the effect on balancing prices and battery profitability, when the LFAS requirements increase over time. The sensitivity increased the LFAS requirements from the base case 110 MW/ 65 MW peak and off-peak, respectively. While in the base case these requirements do not change, in the sensitivity run they were valid for the first year only and were then increased by 10 per cent in the second year, and then another 10 per cent in the final (third) year.

This sensitivity showed that increases in the LFAS requirements do not result in material changes in ESS prices or battery profitability.

Quality assurance processes

The ERA undertook quality assurance processes at different stages of preparing the model and reviewing the model outputs. These included:

- reviewing the model inputs
- verification of the model inputs
- reviewing model outputs
- sensitivity analysis.

Model inputs relevant to individual generators were collected from market participants. These data build and update data already provided by most participants under the WEM Rules.[79] This information was collated and compiled with other physical generator characteristics relevant to the modelling and provided to market participants for review. Basic information was also collected from expected battery operators, however, that data is based on high level assumptions.

[79] Wholesale Electricity Market Rules (WA), 1 July 2022, Rule 2.16, (online)

Discussions were held with AEMO regarding the scheduling of essential system services, and market constraints. The application of the GIA constraints programmed into the model was compared against historical observed constraint application to test the model's validity.

Battery investment case model

Section 4.2.1 of this paper stated the ERA's reasons for investigating the investment case for battery storage in the WEM. The aim of this modelling is to assess the efficiency of WEM price signals in driving commercial investments needed to meet the WEM Objectives. The investment model helps to understand the factors that affect investment in battery storage. This model uses forecast revenues for battery storage for facilities from the ERA's WEM model.

The investment in battery storage was compared to the current Benchmark Reserve Capacity Price (BRCP) reference generator (160 MW liquid-fuelled open cycle gas turbine (OCGT)) to draw conclusions on the efficiency of price signals being generated in the WEM. The results are explained in sections 4.2.1 to 4.2.3 of this paper.

This section lays out the background on the BRCP, the model's assumptions, and the method applied.

Battery storage basics

A battery storage's costs depend on its capacity and duration. In general, the larger the battery's capacity and duration, the more expensive the battery. For example, a 100 MW battery with 200 MWh stored is less expensive than a 100 MW battery with 400 MWh stored. Both batteries have the same amount of capacity but differ in how long they can provide that capacity to the grid. Of the battery storages facilities that have the same capacity, the longer the duration (i.e., more energy stored) the more physical infrastructure is needed to hold the extra stored energy which has an associated higher overall cost.

The major advantage of longer duration battery storage is its ability to provide electricity to the grid over longer periods of time. For example, a 2-hour battery (e.g., a 100 MW/ 200MWh battery) is likely to have fully discharged within 2 hours (assuming its total capacity is being discharged during this time) and thus if the grid needs continual electricity over 3 hours, a 2-hour battery cannot provide it. Investors in battery projects will assess the benefits of different duration batteries against the possible revenue streams and the associated costs. For the WEM, one revenue stream can be earned from obtaining capacity credits, which, for a battery, depends on how much electricity it can provide over a 4-hour window set by AEMO.

Battery storage revenue sources

The WEM allows a battery storage system to earn revenue from participating in:

- The balancing market. A battery's ultimate use is to store energy for later use. A battery can make money by charging (i.e., buying) when electricity is cheap and discharging (i.e., selling) when the price is high. This is called energy arbitrage. This makes commercial sense when the difference between the buy and sell price is greater than the cost of cycling the battery, the costs associated with energy losses, and alternative revenue options for the battery's stored electricity.
- The essential system services markets. A battery is a highly flexible source of electricity that can provide many ESS services. ESS participation is attractive for battery operators

as the battery does not necessarily need to cycle to provide the service as they are paid for offering the service. Less cycling helps to prolong the life of the battery.

- The reserve capacity mechanism. Capacity credits are allocated to electricity resources depending on how much capacity they can make available to the WEM during periods when the system requires capacity the most to maintain the reliability of the system.[80] Batteries will receive capacity credits depending on how much electricity they can provide from 4:30pm to 8:30pm each day.[81] The critical characteristics are how much capacity the battery can provide (i.e., size) and for how long it can provide this electricity (i.e., duration).

Battery storage investment case assumptions

Table 1 lists the assumptions used in the battery storage investment case modelling.

Table 1: Battery storage investment case modelling assumptions

Assumption	Unit	Description
Battery life	15 years	Battery life before it must be replaced.[82]
Round-trip efficiency	85 per cent	A round-trip efficiency is the amount of electricity lost when both charging and discharging a battery. For example, a 100 MWh battery with 85 per cent round-trip efficiency means that it requires 108 MWh to charge up to 100 MWh and then return 92.5 MWh when discharging. This assumes that the lost electricity is 7.5 per cent when charging and again 7.5 per cent loss when discharging totalling 15 per cent for the full charging and discharge cycle.
Discharge efficiency	7.5 per cent	The discharge efficiency is the level of electricity that can be returned to the grid from the charged battery. For example, a battery may charge up 100 MWh, but when it returns this back into the grid, it only returns 92.5 MWh. This difference is referred to as the discharge efficiency and in this case is 7.5 per cent (1 - 92.5 MWh / 100 MWh).
AUD / USD exchange rate	$0.70 USD/AUD	Rate used to convert USD battery cost estimates into the Australian dollar equivalent.

80 The method for determining the capacity credit allocations is performed by AEMO following Wholesale Electricity Market Rules (WA), 1 July 2022, section 4.11. For battery storage, clause 4.11.3 of the WEM Rules assesses a battery's capacity credits dependent on a how much electricity the battery can supply over four hours.

81 AEMO currently requires a battery's electricity from 4:30 pm to 8:30 pm each day which generally coincides with the day's peak demand. AEMO can amend this time window. Australian Energy Market Operator, June 2022, *2022 Reserve Capacity information Pack*, (online), [accessed 26 June 2022].

This also assumes there is no reduction in capacity credits due to the application of the Network Access Quantity regime which reduces capacity credits for new electricity resources built in congested parts of the network.

82 Based on information from stakeholders and battery operators outside of the WEM.

Assumption	Unit	Description
Battery construction time	1 year	Time taken to construct a battery so that it is able to participate in the balancing market, ESS markets, and RCM.
Discount rate	8.37 per cent	For simplicity, a single long-term nominal Weighted Average Cost of Capital discount rate was used. This is based on the BRCP method (detailed in the BRCP Market Procedure) for calculating the WACC in real terms and converted into a nominal rate based on the mid-point of the RBA's expected inflation range.[83]
Expected long term RBA inflation rate	2.5 per cent	

Source: ERA inputs from market and publicly available information.

For comparison, the ERA estimated the BRCP based on the current reference technology which is a 160 MW OCGT. The estimate is based on the actual BRCP prices determined for the 2022/23 to 2024/25 capacity years. As the BRCP for 2025/26 has not yet been determined, the BRCP has been increased by the expected inflation rate from the RBA's May Statement on Monetary Policy.[84] Into the later years, the expected inflation rate of 2.5 per cent is used to increase the BRCP.[85]

It is assumed that the capacity credit price equals the BRCP as that is the price that will encourage capacity to be built in the SWIS. This allows the model to assess if the WEM price signals encourage entry to the market when the level of excess capacity in the system is low.

The Benchmark Reserve Capacity Price (BRCP)

To price capacity, a benchmark price is determined that would deliver enough revenue from capacity payments to attract capacity providers to the SWIS. The BRCP establishes the marginal cost of providing one additional megawatt of reserve capacity in the relevant capacity year. The BRCP is calculated by undertaking a technical, bottom-up cost evaluation of the entry of a new 160 MW OCGT generation facility in the SWIS in the relevant capacity year. This is the current reference generator. However, EPWA is considering its appropriateness for future BRCP determinations as part of its reserve capacity mechanism Review.

Battery storage investment case method

The battery storage investment case looks at the cost of building a battery and breaks down this cost based on the expected capacity credits that the battery is likely to receive.[86] For this analysis, the ERA used the method in the WEM Rules to calculate a battery's likely capacity credits. This is based on the amount of electricity that a battery can provide over the 4-hour

83 This uses a similar method for determining the WACC for the BRCP. This has been calculated based on available data and will differ to when the ERA must make its WACC calculation for the upcoming 2023 BRCP. See Market Procedure: Benchmark Reserve Capacity Price, 9 November 2020, (online).

84 Reserve Bank of Australia, 2022, *Statement on Monetary Policy – May 2022*, p 60.

85 2.5 per cent is the mid-point of the RBA's inflation target range of 2 to 3 per cent per annum.

86 This is so that it can be compared to the current BRCP reference generator (a 160 MW OCGT).

duration window.[87] For example, a 100 MW battery with 200 MWh stored at the start of the 4-hour duration window, can provide 50 MWh per each hour in the 4-hour window before it is empty and thus would receive 50MW in capacity credits.[88] AEMO has allocated 46.25 capacity credits to Synergy's 100 MW / 200 MWh battery for the 2025/26 capacity year which the ERA has used as a starting point.[89]

Using a similar method to how the BRCP is determined, the ERA determined the amount of revenue (energy, ESS and capacity) that the battery storage would need to make per capacity credit to break even based on the assumptions in Table 1. The following other assumptions were also made:

- The battery will always be charged up to the required level to receive full capacity credits by the start of the Electric Storage Resource Obligation Interval.
- The battery takes one year to build and receives no capacity revenue whilst it is under construction. The battery's life begins from the date construction finishes.
- It is assumed that the battery will make a constant revenue amount per year from the energy, ESS, and capacity markets over the life of the battery.
- The net present value of the required revenue uses the 8.37 per cent discount rate.
- The battery storage system costs come from the National Renewable Energy Laboratory's (NREL) cost projections for large scale battery storage projects and adjusted as per the assumptions above.[90]
- The battery storage costs used in this investment model is the mid cost forecast for that battery's duration.
- The NREL costs assume that enough maintenance is performed annually to keep the battery operating without significant degradation from the battery's performance in its first year. That is, it is expected that the battery's performance does not degrade over time due to enough maintenance and is factored into the costs. Thus, no separate adjustment is made for degradation as it is already incorporated into the costs.

Battery storage investment case results

Figure 7 shows three cost curves (high, mid, and low) for a 2-hour duration battery. The shape of the curves shows a decreasing cost over time as battery technology matures. This decrease in costs is driven by expected process efficiencies to build battery storage and falling development costs as learnings from more battery storage construction are incorporated into future builds. For simplicity, only the analysis for a two-hour duration, 100 MW battery storage is presented in this discussion paper.[91]

87 Changes to the duration of the Electricity Storage Resource (ESR) obligation intervals directly affects the capacity credits that a battery storage facility can obtain which consequently affects the battery's capacity credit revenue. This affects the feasibility of the battery storage facility due to this revenue uncertainty and that battery storage cannot be augmented easily to adapt to a longer ESR obligation interval duration.

88 This example assumes no overbuilds or losses during discharge.

89 Australian Energy Market Operator, 2022, *Capacity Credits assigned since market start,* (online), [accessed 26 June 2022]

90 NREL's costs these were determined for a 4-hour duration battery, the storage costs were replicated to determine the costs of 2-hour and 6-hour duration batteries as well. The costs were converted into AUD at a rate of $0.70USD and the curves for the 2-hour and 6-hour batteries follow the same shape as the 4-hour battery cost curves.

91 Both 4-hour and 6-hour duration batteries were also assessed by the ERA. The main findings were similar to the 2-hour battery duration case.

Based on the required amount of revenue per capacity credit to provide battery storage capacity, the middle cost case does not become cheaper than the current BRCP reference generator (160 MW OCGT) until around 2029 (see Figure 7). This means that it is more expensive to install battery storage to provide capacity than installing a generator like the BRCP reference generator, assuming the costs of the BRCP reference generator increase as forecast.

The investment case for battery storage requires at least $6 million in profit margins from the energy and ESS markets to make it a cheaper alternative than the current BRCP OCGT. However, this amount of revenue decreases each year as the expected capital costs of battery storage decreases, and the cost of building the BRCP OCGT increase.

The ERA's model of the WEM (also described in this appendix) shows a decreasing revenue profile for battery storage as more enter due to competition and a relatively small sized market. This means that battery storage would need to rely mostly on capacity revenues to make them bankable investments in the SWIS. Apart from capacity revenue, the other revenue from energy arbitrage and ESS markets are highly uncertain and this revenue uncertainty raises the risks and thus the attractiveness of battery storage investments in the WEM.

Appendix 6 Cross jurisdictional review: Battery storage participation

Generally, a resource owner that has market power can profit by raising clearing prices above competitive levels. Market power mitigation ensures market outcomes, such as clearing prices, resource schedules, and dispatch instructions, are consistent with competitive outcomes.[92] Internationally, work has been undertaken to develop market power mitigation mechanisms to ensure that batteries participate competitively in existing day ahead, real-time, ancillary service and capacity markets, to reflect the system's cost to supply and not the exercise of market power.

Advancements in other jurisdictions can help inform the development of market power mitigation mechanisms in the WEM, which will become increasingly important as the penetration of batteries increases and as different types of battery systems are introduced to the market.[93] [94]

Failing to adapt market power mitigation mechanisms to account for the unique operating characteristics of these systems could lead to them either being inefficiently under mitigated, allowing them to exploit their position in the market, or over-mitigated, preventing them from offering their full value and benefits to the market.[95] Neither option is in the best interest of consumers.

North American markets are making significant progress in this area. On 15 February 2018, the Federal Energy Regulatory Commission (FERC) issued Order No. 841, requiring the development of electric storage participation models in markets operated by Regional Transmission Organisations (RTOs) and Independent System Operators (ISOs) in each FERC jurisdiction.[96] The participation models were required to recognise the physical and operational characteristics of electric storage resources, and facilitate their participation in the FERC jurisdictions by:

- Ensuring that a resource using the participation model:
  - is eligible to provide all capacity, energy, and ancillary services that the resource is technically capable of providing in the markets, and
  - can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer consistent with existing market rules that govern when a resource can set the wholesale price.
- Accounting for the physical and operational characteristics of electric storage resources through bidding parameters or other means.

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92 American Wind Energy Association, September 2020, *Hybrid and co-located resource market power mitigation: An examination of the applicability of current ISO/RTO mitigation provisions to hybrid and co-located resources*, (online).

93 Such as co-located battery and renewable resources (e.g., PV or wind) operating separately behind the one connection point, hybrid battery and renewable resources operating as one unit behind the one connection point, and storage as a transmission asset, which is a battery connected to a transmission system operated only to support the transmission system.

94 The ERA previously provided a high-level discussion on the implementation of battery storage technology in Appendix 5 of its *Report to the Minister for Energy on the Effectiveness of the Wholesale Electricity Market 2018: Final Report, p. 57,* (online).

95 American Wind Energy Association, September 2020, Hybrid and co-located resource market power mitigation: An examination of the applicability of current ISO/RTO mitigation provisions to hybrid and co-located resources, p. 4, (online).

96 Federal Energy Regulatory Commission, 28 February 2018, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators* (online).

- Establishing a minimum size requirement for participation in the markets that does not exceed 100 kW.
- Specifying that the sale of electric energy from the markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale locational marginal price.

Some FERC jurisdictions are only just beginning their journey toward implementing battery participation in their markets, such as the Midcontinent ISO (MISO), which hosted a 'Getting Started with Electric Storage Resources Registration and Enrolment' workshop on 9 May 2022.[97]

Others are well advanced and already grappling with how to implement systems encompassing multiple technologies, such as California ISO (CAISO), which had a battery penetration of 490 MW in 2020, that increased by 2,419 megawatts (MW) in 2021.[98] CAISO was anticipating that by June 2022, a further 2,100 MW would also be online.[99] [100]

The interconnection queues of the various North American jurisdictions indicate that CAISO will not be alone in the development of an expanding battery fleet.[101] Table 2 provides an overview of the quantities of battery capacity represented in a selection of FERC jurisdiction interconnection queues.

Table 2: Quantity of battery resources in interconnection queues in FERC jurisdictions

Jurisdiction	Interconnection queue
CAISO	In 2021, CAISO had approximately 51,380 MW in standalone battery projects, 18,606 MW of hybrid battery and solar projects, and 5,036 MW of hybrid battery and wind projects in its active interconnection queue.[102,103]
Pennsylvania New Jersey Maryland (PJM)	From the queue dates representing active projects in 2022, there were approximately 20,500 MW in storage projects and 4,650 MW in hybrid solar and storage projects in the PJM interconnection queue.[104]
New York ISO (NYISO)	On 31 March 2022, there were approximately 10,500 MW of battery projects in the NYISO interconnection queue.[105]

97 The FERC approved effective date for storage-related Tariff revisions, allowing storage greater than 100kW to start participating once registered with MISO, was 6 June 2022. MISO Dashboard (18 May 2022) 'Storage Participation – FERC Order 841 Compliance (fka IRO62), (online) [accessed 28 June 2022].

98 For an overview of how these resources participate in a market, see: California ISO, 4 April 2022, *Hybrid Resource – Interim Participation Options*, (online).

99 California ISO, 4 March 2022, 'New video on historic growth of battery storage released,' (online) [accessed 27 June 2022].

100 CAISO was moving quickly to fill a 3,300 MW procurement mandate from the California Public Utilities Commission prior to 2023. See California ISO Memorandum, ISO Board of Governors, 11 November 2020, Decision on hybrid resources policy proposal, p. 75 of California ISO, 8 September 2021, *Hybrid Resources and Co-located Resources*. Docket No. ER-2853-000, (online).

101 An interconnection queue is a list of generation or transmission projects that are proposed and waiting to join the system. Different jurisdictions can have different information presented in varying formats.

102 California ISO, Resource Interconnection Management System, (online) [accessed 29 June 2022].

103 Note these numbers do not include behind the meter batteries installed in households or businesses that participate under state or local tariffs.

104 PJM, New Services Queue, (online) [accessed 29 June 2022]

105 New York ISO, Interconnection Process, (online) [accessed 28 June 2022].

Jurisdiction	Interconnection queue
Southwest Power Pool (SPP)	The SPP interconnection queue dashboard indicated that for 2022, active projects included 2,040 MW of battery and 1,100 MW of hybrid capacity.[106]
MISO	On 22 July 2021, there was about 11,000 MW of battery projects and 9,500 MW of hybrid projects in the MISO interconnection queue.[107]

General market power mitigation

In most jurisdictions, batteries are subject to the same general tests for market power or the exercise of market power, and the same market power mitigation, as any other resource.

The two main types of exercise of market power considered in other jurisdictions, particularly related to batteries, are:

- Economic withholding, which occurs when a resource is physically available but at offer prices exceeding short-run marginal cost (SRMC), and
- Physical withholding, which generally occurs when a resource fails to offer all its available supply to the market (e.g., by taking a false outage or understating maximum operating limit).[108]

Additional types of exercise of market power may vary by jurisdiction. For example, CAISO and SPP consider uneconomic production, which involves increasing the output of a facility to levels that would otherwise be uneconomic, to obtain benefits from a transmission constraint.[109,110]

Some jurisdictions rely on an ex-post approach to market power mitigation where, if the regulator suspects or is alerted to anticompetitive conduct, it will investigate that behaviour (e.g., the New Zealand market).[111]

Other jurisdictions use various structural tests or ‘conduct and impact’ tests as an interim automated step in the market clearing process, to determine the presence of structural market power or the exercise of market power, respectively. If detected, the resource’s offer may be automatically mitigated and replaced with a lower offer that better reflects the resource’s actual cost i.e., its short run marginal cost (referred to as a ‘reference level’ in North American jurisdictions), which is considered more consistent with a resources competitive offer.[112]

The three pivotal supplier test measures the degree to which the supply from three suppliers is required to meet demand to relieve a specific constraint, while maintaining a competitive

106 Southwest Power Pool Generation Interconnection Queue Dashboard (online) [accessed 28 June 2022].

107 MISO, Generator Interconnection Queue, Interactive Queue, (online) [accessed 28 June 2022].

108 Ibid, p. 6.

109 Fifth Replacement FERC Electric Tariff (Open Access Transmission Tariff) (California Independent System Operator Corporation), Effective as of 1 April 2022, (online).

110 Southwest Power Pool, 18 May 2022, Market Protocols: SPP Integrated Market Place Revision 89, Clause 8.2.2.3, (online).

111 For example, see The Brattle Group (2020) New Zealand Electricity Authority’s Preliminary Decision on UTS (online).

112 American Wind Energy Association, September 2020, Hybrid and co-located resource market power mitigation: An examination of the applicability of current ISO/RTO mitigation provisions to hybrid and co-located resources, p. 8, (online).

structure. Three suppliers are considered jointly pivotal if there are not enough megawatts to satisfy the constraint without using the top two suppliers' output, plus the output of the supplier being tested.[113] The two main variables underpinning this test are demand, consisting of the incremental megawatt value required to relieve the constraint, and supply, consisting of the incremental megawatts of supply available to relieve the constraint.[114]

The conduct and impact test involves two steps:

- Conduct test – a behavioural screen to determine whether an offer for a resource exceeds its reference level by a pre-determined threshold.
- Impact test - if the offer for a resource fails the conduct test, an impact test is conducted to determine whether the impact that the offer has on market clearing prices exceeds a pre-determined threshold.

An overview of the general market power mitigation mechanisms in various jurisdictions that battery resources are subject to is provided in Table 3 below.

Table 3: General market power mitigation mechanisms in various jurisdictions

Jurisdiction	Approach to mitigation	Market Power Test	Mitigation
CAISO	Structural	Screen for market power - Three Pivotal Supplier test.	Offers of resources found to be pivotal suppliers automatically mitigated to the higher of the reference level or a competitive proxy price.[115]
PJM	Structural	Screen for market power - Three Pivotal Supplier test	Offers of resources found to be pivotal suppliers automatically mitigated to reference level offers.
ERCOT[116]	Structural	Screen for Market Power – Big Fish	Applies market power mitigation only to market participants owning five per cent or more of installed capacity. These market participants can submit a voluntary mitigation plan.
MISO, ISO-NE, NYISO, and SPP.	Conduct and Impact	Test for exercise of market power: Conduct and Impact test.	An offer for a resource is only mitigated to a reference level if it fails both the conduct and impact tests. For example, in SPP, the conduct threshold for a resource located in

[113] PJM, 7 June 2022, *PJM Manual 15: Cost Development Guidelines*, p. 13, (online).

[114] Houston Kemp Economists, May 2018, *International Review of Market Power Mitigation Measures in Electricity Markets: A report for the Australian Competition and Consumer Commission,* p. 17, (online) for an overview of how this test is applied in the energy and regulation markets of the PJM jurisdiction.

[115] Bid mitigation is triggered in energy imbalance markets in areas, which are separated by congestion from the rest of the CAISO system and are structurally uncompetitive. For example, the Western Energy Imbalance Market employs bid caps for start-up and minimum load bids, based on pre-determined unit specific costs plus 25 per cent and opportunity cost. Local market power mitigation (within balancing areas) involves energy bid mitigation triggered only when congestion occurs on uncompetitive constraints, and only for units that can relieve the congestion. Market bids are capped using cost-based energy bids plus a 10per cent adder. California ISO, 2 June 2022, *Western Energy Imbalance Market, Monitoring and Mitigating Market Power*, (online).

[116] ERCOT is the Electric Reliability Council of Texas. Unlike, the other jurisdictions in this table, it is regulated by the Public Utility Commission of Texas (not FERC).

Jurisdiction	Approach to mitigation	Market Power Test	Mitigation
			a Frequently Constrained Area (FCA) is 17.5 per cent above the mitigated energy offer curve, otherwise, if not in FCA, it is 25 per cent above the mitigated energy off curve.[117]

One limitation of the use of thresholds to determine whether the exercise of market power has occurred following conduct and impact tests is that the conduct test is triggered by a large deviation from the resource's competitive offer price only, with suppliers able to bid right up to the threshold without being mitigated. For resources with higher reference levels, the difference between the offer price and threshold that can be bid is greater than for those with lower reference levels. The impact test may then only be triggered if the price impact is substantial.[118]

This issue is not just relevant to batteries. However, given the State Government's new focus on battery storage technology to address reliability issues in the system, and on implementing the use of conduct and impact tests for the mitigation of market power, it is important to ensure that the SRMCs of battery resources are accurate.[119] Setting a suitable threshold will require balancing the need for it to be not too high (reducing the possibility of detrimental bidding up to the cap), and not too low, so as to not allow for the recovery of the facility's costs, which will hinder investment.

As with economic withholding, thresholds may be employed for identifying physical withholding. For example, in the ISO-NE market, the Internal Market Monitor (IMM) employs the following initial thresholds to identify the physical withholding of a resource:

6. Withholding that exceeds the lower of 10 per cent or 100 MW of a resource's capacity.

7. Withholding that exceeds, in the aggregate, the lower of 5 per cent or 200 MW of a market participant's total capacity for market participants with more than one resource, or

8. Operating a resource in real-time at an output level that is less than 90 per cent of the ISO's dispatch rate for the resource.[120]

In the PJM jurisdiction, the must-offer rule in the capacity market is one component of an extensive framework for mitigating supply-side market power and, is an important mechanism allowing PJM and PJM's IMM to mitigate physical withholding.[121]

Safe harbour provisions are included in several markets that allow batteries to not have their bids or offers mitigated if their energy offer curve is below a minimum offer curve threshold, or if they are smaller than a reasonable threshold and are not owned by entities that also control other resources that could benefit from higher prices. For example, in the SPP market,

117 This is for a resource with an energy offer curve greater than or equal to $25/MWh that was not committed to address a local reliability issue.

118 Potomac Economics, 7 May 2021, *2020 State of the Market Report for the MISO Electricity Markets,* p. 23 (online).

119 Energy Policy WA, 2021, *Improvements to the Market Power Mitigation Mechanism – Information Paper*, p. A-1, (online).

120 ISO New England, 27 August 2021, Market Rule 1, Appendix A, Market Monitoring, Reporting and Market Power Mitigation, Clause III.A.4.2, (online).

121 CAISO also requires that batteries, along with other resources in its fleet, are subject to a must offer obligation.

resources with an energy offer curve below $25/MWh are not subject to mitigation measures on their energy offer curve for economic withholding.[122]

In the CAISO jurisdiction, batteries less than 5 MW are not subject to market power mitigation.[123] As explained by the Market Surveillance Committee (MSC) of CAISO, the consequences associated with mitigating small storage facilities may outweigh the benefits of that mitigation. Given the rapid advances in battery technology and the way that it is operated, the MSC consider that it is easy for a mitigation scheme to mis-characterise the costs and abilities of a battery, raising its costs, and potentially reducing its value in balancing load over net peak hours, and discouraging investment.[124]

The ERCOT jurisdiction mitigates resource offers that significantly exceed marginal cost to an estimate of that resource's SRMC pursuant to voluntary mitigation plans submitted by the resource owner.

Market power mitigation of multiple technology resources

More recently, international jurisdictions (such as CAISO and NYISO) are considering how to mitigate the exercise of market power by multiple technology systems, such as:

- Co-located resources – a battery co-located with another technology, operating separately behind one limited connection point, and
- Hybrid resources – a battery co-located with another technology*,* operating as one unit behind the one connection point.

Important questions, for example, focus on:

- How to differentiate between instances of genuine anti-competitive physical withholding, which can inflate prices for other, less economic generators, and a hybrid resource optimizing joint operation of its component resources.[125]
- How to ensure that co-located resources that are treated as individual facilities behind the same connection point are not overcompensated in the capacity market, particularly where the total of the capacity credits is more than the connection point (which can also put reliability at risk).

New York ISO

The NYISO filed proposed revisions to its Tariff with FERC on 29 January 2021 to enable a battery and a wind or solar resource to share a common point of injection and collectively participate in the NYISO market as a Co-located Storage Resource (CSR). CSRs would submit offers, receive schedules, and be settled separately. Schedules for CSR generators

122 Southwest Power Pool, 18 May 2022, Market Protocols, SPP Integrated Market Place Revision 89, Clause 8.2.2.3, (online).

123 Fifth Replacement FERC Electric Tariff (Open Access Transmission Tariff) (California Independent System Operator Corporation), Effective as of 1 April 2022, Clause 34.1.5.1, (online).

124 Members of the Market Surveillance Committee of the California ISO, 9 September 2020, *Opinion on Energy Storage and Distributed Energy Resources* Phase 4, p. 2 (online).

125 Ibid.

would account for limitations on their combined output due to the capabilities of the CSR's interconnection facilities (i.e., the CSR injection scheduling limit).[126]

As part of this filing, NYISO specifically noted that artificial withholding of the CSR generators' output could cause inflated locational based marginal prices or increase guarantee payments to other, less economic, generators. Accordingly, NYISO proposed enhancements to its market power mitigation measures to address possible physical withholding of either or both CSR generators and to give its operators additional tools to address CSRs that fail to operate within their NYISO-issued schedules and dispatch.[127]

Specifically, NYISO proposed revisions to its energy market's physical withholding conduct thresholds to address the possibility that a market participant could reduce its submitted CSR injection or withdrawal scheduling limits as it bids to physically withhold one or both CSR components from providing energy or ancillary services. NYISO proposed to apply the same conduct thresholds that it applies to other types of physical withholding. In particular, the proposed conduct thresholds would be violated given:

- withholding that exceeds 10 percent or 100 MW of a CSR scheduling limit outside the New York City Constrained Area, or
- withholding that exceeds 10 percent or 50 MW of a CSR scheduling limit in the New York City Constrained Area while a constraint is active.[128]

NYISO further proposed a revision to recognise that a battery may incur costs that it is eligible to recover from the NYISO when the battery is required to purchase energy at a higher price than it would otherwise be expected to pay to respond to a NYISO supplemental reliability evaluation or out-of-merit instruction to protect system or local reliability.[129]

On 19 July 2021, in response to questions from FERC, NYISO submitted a report noting its intention to develop a participation model for Hybrid Storage Resources (HSR), offering the opportunity for multiple assets behind a common point of injection to operate as a single resource, submitting offers, receiving schedules, and being settled as a single resource.[130] At that time, a key proposed change to the operation of a wind or solar generator participating in a CSR was that when a pair of CSR generators' combined energy and ancillary service schedules was within 10 percent of the CSR injection scheduling limit, the NYISO would instruct the wind or solar resource not to exceed its NYISO-issued schedule.[131]

This would be accomplished through the application of a wind or solar output limit, providing a buffer to ensure the deliverability of scheduled ancillary services and energy from the participating storage resource, given the potential for unexpected increases in output from the co-located wind or solar resource. When a wind and solar output limit was applied, the

126 Federal Energy Regulatory Commission, 30 March 2021, *Order Accepting Proposed Tariff Revisions to Implement Participation Model for Co-Located Storage Resources*, Docket No. ER21-1001-000, p. 1, (online).

127 Ibid p. 12.

128 Ibid.

129 However, on 2 August 2021, in a report on NYISO's progress to test and complete the software changes needed to implement its CSR participation model, NYISO noted that in developing its software, it found that coordinating the enforcement of the point of interconnection constraints with asset-specific for each CSR generator was more complex than was envisioned during the market design phase.129 NYISO hoped to have implemented its new model by the end of 2021. See New York Independent System Operator, Inc, 2 August 2021, *Informational Report on Co-located Storage Resources Implementation Progress*; Docket No. ER21-1001-00__ p. 1, (online).

130 NYISO, 19 July 2021, *Report of the New York Independent System Operator, INC. Hybrid Resources* Docket No. AD20-9-000, p. 2, (online).

131 Ibid.

renewable resource would not be paid for output greater than its schedule, plus a three percent upper operating limit tolerance.[132] Inadvertently, this would also mitigate the implications for market prices from over production.

California ISO

The path toward implementation of multiple technology facilities in the Californian jurisdiction has been a little different to that for New York. On 16 October 2020 CAISO noted that there could be several thousand megawatts of hybrid capacity joining the system in the coming years, with some projects situated in local areas with thin capacity margins. CAISO considered that these projects may have a greater potential to exercise market power. CAISO requires that hybrid resources bid in their full capability, like other resources, but with the understanding that hybrid resources have periods when they may charge underlying battery components, and periods where energy is coming from potentially variable sources.[133]

CAISO considered initially that it was not planning to implement market power mitigation and would monitor all hybrid resource forecasts and bids for strategic behaviour. To do this, CAISO noted its intention to collect forecast data on the variable resource components as well as bid and outage data, so that it could monitor, check, and understand hybrid resource bidding practices. CAISO indicated that it would likely include this capability in a future version of the hybrid resources initiative to address this concern.[134,135]

On 8 September 2021, CAISO submitted a marked tariff to FERC, including revisions to its market power mitigation process to accommodate hybrid resources in the day ahead and real time markets. The day-ahead market power mitigation process optimises resources to meet demand reflected in demand bids, including export bids and virtual demand bids, and to procure one hundred percent of ancillary services requirements based on supply bids submitted to the day ahead market. The revision to this section noted that hybrid resources and batteries are considered in the market power mitigation process, i.e., they are subject to all mitigation under the CAISO tariff, including local market power mitigation, but they are not subject to bid mitigation.[136] [137]

Similar revisions were made to the real time market power mitigation process for hybrid resources in which the CAISO conducts a market power mitigation process, the result of which informs the real time market optimisation process.[138] CAISO accepted these tariff revisions on 30 November 2021.[139]

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132 Ibid, p. 9.

133 California ISO, 5 October 2020, *Hybrid Resources, Final Proposal*, p. 18, (online).

134 Ibid.

135 American Wind Energy Association, September 2020, *Hybrid and co-located resource market power mitigation: An examination of the applicability of current ISO/RTO mitigation provisions to hybrid and co-located resources*, p. 21, (online).

136 Refer to section 31 of the marked-up tariff in California ISO, 8 September 2021, *Hybrid Resources and Co-located Resources*. FERC Docket No. ER-2853-000, (online).

137 Since this time, CAISO appears to have made further progress in determining how it will mitigate batteries and renewables co-located behind the same connection point. For example, see California ISO, 13 May 2022, Day-Ahead Market Enhancements discussion (online), which includes illustrated examples of local market power mitigation in the integrated forward market and imbalance reserve markets (i.e., for energy and imbalance reserve up).

138 Refer to section 34 of the marked-up tariff in California ISO, 8 September 2021, *Hybrid Resources and Co-located Resources*. FERC Docket No. ER-2853-000, (online).

139 Federal Energy Regulatory Commission, 30 November 2021, *California Independent System Operator Corporation, Docket No. ER21-2853-000, Order Accepting Tariff Revisions*, (online).

Market power mitigation of storage as transmission only assets

The market power mitigation of storage as transmission only assets (SATOA) that are connected to the transmission system and operated only to support the transmission system are also receiving some attention. For example, in the SPP market, market power mitigation is being introduced such that the owner of a SATOA cannot:

- Own assets registered in energy or operating reserve markets.
- Participate in interchange transactions, virtual energy offers, virtual energy bids, or bilateral settlement schedules.
- Submit monetary offers for the injections or withdrawals associated with a SATOA.

The SATOA is settled at the Locational Marginal Price (LMP) and operates only to provide the services for which it was installed.[140]

The reference level – the short run marginal cost of a battery

Internationally, given the requirement for batteries to participate in markets in the same way as other technologies, including being subject to structural and behavioural testing and the mitigation of prices to SRMC, much thought has already been invested into how SRMC should be calculated for batteries. Most jurisdictions allow for consultation-based calculation of SRMCs that may include opportunity costs, legitimate risks, and justifiable technical characteristics, subject to review and approval by the regulator.

An alternative method includes the development of offer based SRMCs calculated, for example, as the lower of the mean or the median of the resource's accepted offers during competitive periods in similar hours or load levels during prior days (sometimes adjusted for fuel prices). Price based SRMCs may also be calculated, for example, as the weighted average or mean of a portion of the lowest locational marginal prices at a resource's location in periods the resource was dispatched in a set number of previous days.

An overview of the different methods employed for the calculation of reference levels in a selection of FERC jurisdictions is provided in the table below.

Table 4: Overview of methods for calculating reference levels in FERC jurisdictions

Market	Price-based	Offer-based	Consultation-based
CAISO	Locational Marginal Price (LMP) based Default Energy Bids (DEBs) calculated from the weighted average of the lowest 25per cent of LMPs at resource's location in periods resource was dispatched in prior 90 days.		Cost based DEBs calculated according to CAISO's Variable Cost option, a formulaic calculation based on a resource's heat rate, fuel prices, and variable O&M. Consultation-based DEBs developed through "Negotiated Rate" option available in tariff, which

140 Other jurisdictions are also developing models to incorporate storage as transmission assets. For example, see PJM, Storage as a Transmission Asset, (online) [accessed 29 June 2022]; and MISO, MISO (14 February 2022) Dashboard: Storage as Transmission-Only Asset (SATOA) PAC004, (online) [accessed 29 June 2022]

Market	Price-based	Offer-based	Consultation-based
			may include opportunity costs.
NYISO	Price based reference level calculated as mean of location based marginal prices at a resource's location during the lowest-priced 50per cent of hours the resource was dispatched during the prior 90 days.	Offer based reference level calculated as the lower of the mean or median prior accepted offers in peak periods deemed to be competitive during the prior 90 days.	Consultation based level from prior consultation with NYISO and calculated in accordance with NYISO specifications.
MISO		Offer based reference level calculated as the lower of the mean or the median of the resource's accepted offers during competitive periods in similar hours or load levels during the prior days, adjusted for fuel prices.	Cost based Consultative - Consultation based reference level, which may include prudent risk premiums and opportunity costs, or justifiable technical characteristics for physical offer parameters, subject to review and approval by the market monitor.
ISO-NE	LMP based reference level equal to the mean of the LMP at the resource's location during the lowest-priced 25per cent of hours that the resource was dispatched during the previous 90 days in similar hours, adjusted for fuel prices.	Offer based reference level calculated as the lower of the mean or median of a resource's accepted offers in competitive periods during the prior 90 days, adjusted for fuel prices.	Cost based reference level developed in consultation with the market monitor and consistent with the methods prescribed in the tariff.

In the PJM market, market participants are responsible for developing their own cost-based offers, and the accuracy of these offers, based on instructions in section 11 of its Manual 15. This information is then provided to PJM or the PJM MMU, as required. PJM uses the cost-based offers to determine each unit's production costs (i.e., the cost to operate the unit and to schedule generation in cases where structural market power is found to exist).[141]

Market participants with batteries in the PJM market must identify the methodology they use to calculate their charging cost and efficiency factor in their fuel cost policies.[142] Operating costs can include, but are not limited to, acids and lithium-ion replacements. Batteries cannot include costs that can be included in their capacity offer, such as labour. Maintenance costs may include but are not limited to cell repairs/replacements, inverter maintenance, and generation owned interconnection transmission maintenance.[143]

For PJM regulation costs, storage unit losses are calculated as the average of seven days of rolling hourly periods (consisting of the unit's last 168-hour periods with accepted regulation

141 PJM, Effective date: 7 June 2022, *PJM Manual 15: Cost Development Guidelines*, p. 73, (online).

142 Efficiency factors measure the ratio of generation produced to the amount of electricity used to charge (otherwise referred to as round trip efficiency).

143 Ibid. p. 74.

offers) where the real time bus LMP ($/MWh) at the plant node is multiplied by the net energy consumed (MWh) when regulating, divided by the regulation offer (MW).[144]

SPP resources also calculate and submit their own mitigated energy offers, which include opportunity costs, based on Mitigated Offer Guidelines. SPP considers that a battery's SRMC should be calculated as the sum of its charging cost, which accounts for roundtrip efficiency, and the resource's opportunity cost. The opportunity cost is calculated as the average profit in the next hour forgone by charging or discharging in the current hour, deriving the expected LMP for the next hour based on the unweighted average of the LMPs in that same hour during the prior 45 days. The SPP assumes that the battery will make charge and discharge decisions on an hourly basis to maximize profit in nearly all cases and serve load at a minimal production cost.[145]

The SPP MMU explains that a battery's optimal charging pattern depends on the changes in expected price during the operating day. Over a longer optimisation period (a day or multiple days) there may be multiple peaks and troughs in prices, which can be evaluated to establish the optimisation subperiods associated with the expected maximum profit. The MMU suggests that the optimal path for batteries may involve charging and discharging multiple times per day and because of this, recognising the opportunity to charge or discharge in the next hour will maximise profit in nearly all cases. Conversely, failing to recognise this opportunity (to charge or discharge) before the next peak will not maximise the profit of the battery and will not serve load at a minimal production cost.[146]

An SPP resource can request an exemption from the requirement to calculate opportunity costs in this manner by submitting a request to use an alternate proposal to the MMU, which has authority to approve or deny this request. SPP resources are also permitted to make intra-day changes to their mitigated energy offers.

The methods for calculating SRMC outlined above, and an understanding of their limitations, can contribute to the development of calculation methods for the SRMC of batteries in the WEM. The case of the CAISO jurisdiction and its journey in developing an accurate SRMC for batteries may be instructive in this regard.

SRMC considerations in the CAISO jurisdiction

In the CAISO jurisdiction, the potential of lithium-ion batteries has been talked about and anticipated for a long time.[147] In 2018, the criticality of successful integration of these batteries into the system was evidenced in CAISO's submission in response to FERC order 841 where it noted that:

> Charging during periods of low prices, or to be able to discharge during periods of high prices, is the most important "service" storage resources provide. This type of dispatchable demand greatly mitigates the "duck curve" issues the CAISO regularly faces, mitigating the reliability risks presented by a significant evening ramp and reducing the curtailments and negative pricing necessitated by oversupply.[148]

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144 Ibid. p. 75.

145 These assumptions are not forward looking and does not recognise the cycling constraints of batteries.

146 Federal Energy Regulatory Commission, 17 October 2019, *Order on Compliance Filing and Instituting Section 206 Proceeding*. (online).

147 California ISO, 4 March 2022, 'New video on historic growth of battery storage released,' (online) [accessed 27 June 2022].

148 California ISO, 3 December 2018, *Filing for compliance with Order No. 841* (online) p. 27.

Over time, with prices for lithium-ion batteries reducing and the technology proving more dependable, the penetration of batteries in the CAISO system has increased at a significant rate, and with some success. The system was tested on the afternoon of 9 July 2021, when demand was very high due to a heat wave and a large wildfire in Southern Oregon placed stress on the grid. CAISO dispatched 1,000 MW of batteries to balance supply and demand and managed to keep the lights on and avoid load shedding.[149]

However, it appears that integration has only been successful to a point. As explained by the CAISO Market Surveillance Committee (MSC), even in this jurisdiction, battery owners are concerned about how deep cycling of batteries can shorten battery life when operated to arbitrage energy prices, and most batteries are instead operated to provide ancillary services.[150]

As recently as 30 November 2021, a FERC Commissioner (James P. Danly) commented on CAISO's serious reliability and adequacy challenges in an order accepting tariff revisions to enhance market participation for hybrid and co-located resources. While the Commissioner agreed with approving the proposal, he noted that:

> I remain concerned that CAISO continues to use band-aids to address its ongoing reliability challenges rather than the emergency surgery that is actually required. Each band-aid may mark a modest incremental improvement, but the patient is still bleeding to death (pp. 19).[151]

This stark warning appears at odds with CAISO's burgeoning penetration of batteries. Essentially, facilities are coming online but they are not participating in the energy market.

A few months prior to this, in August of 2020, CAISO had noted its own view that the current warranty constructs and capacity payments for batteries may not reflect the true costs of owning and operating these devices.[152] CAISO considered that these physical and contractual constraints may have been impeding the resources from wanting to shift large tranches of energy from the afternoon to evening in the energy market to help integrate renewable resources like solar PV.[153] A number of proposals have been put forward to address these issues, as outlined below.

Default Energy Bid Proposal 21 August 2020

Resources in the CAISO market can collect revenue for providing regulation ancillary services through automatic generation control, which may be lower than revenues earned in the energy market. However, participation in the regulation market generally requires the resource to provide less energy overall, which is advantageous for batteries that must purchase energy

149 Ibid.

150 Market Surveillance Committee of the California ISO, 9 September 2020, *Opinion on Energy Storage and Distributed Energy Resources Phase 4*, p. 9, (online).

151 Federal Energy Regulatory Commission statement, 30 November 2021, Commissioner James Danly Concurrence Regarding California Independent System Operator Corporation, Docket No. ER21-2853-000 (online) [accessed 1 June 2022].

152 Much of the fixed cost obtained in capacity payments for regulation services represents warranty contracts that specify an amount of cycling the resource can achieve over a pre-defined time horizon, which is typically one cycle, a full discharge and charge, per day, over ten years of operation for a four-hour storage device. Exceeding this limit could void its warranty or reduce the "guaranteed" calendar life of the battery. California ISO, 21 August 2020, *Energy storage and distributed energy resources Phase 4: Final Proposal*, p. 19, (online).

153 California ISO, 21 August 2020, *Energy storage and distributed energy resources Phase 4: Final Proposal*, p. 19, (online).

from the grid, that encounter efficiency losses on energy purchased, and that will eventually require maintenance because of charging and discharging.[154,155]

Consequently, CAISO proposed a more complex default energy bid (DEB) to reflect the actual marginal costs of batteries more closely, including costs for energy purchased, efficiency losses, cycling costs and opportunity costs.[156]

CAISO explained that cycling costs are particularly relevant to lithium-ion batteries and are incurred as batteries charge and discharge, causing the cells to degrade and making them less effective in total charging capability, eventually requiring cell replacement. CAISO argued that this degradation cost is a marginal cost because it is strictly associated with the operation of the resource, and therefore, should be included in the DEB.

However, as noted by CAISO, the cycling cost is difficult to model as it is non-linear in nature, it may increase with the total depth of discharge of the resource, and it may be technology or chemistry dependent. Accordingly, in its strawman proposal for the calculation of DEBs, CAISO included a dynamically calculated DEB that could change on an interval-by-interval basis directly with depth of discharge or specific dispatch for batteries. At that time, CAISO did not update DEBs at any time during the day, making the proposal a large departure from what CAISO had previously done.[157]

Nevertheless, in the draft final proposal, CAISO chose to eliminate the dynamic nature of its proposal in favour of a more simplified approach to estimating costs for understanding and to reduce the implementation burden.[158] CAISO noted that it was proceeding with the proposed DEB with the understanding that it is not an accurate representation of costs for a resource during all intervals but is a more general 'upper bound' of costs for storage. CAISO considered that its DEB was prudent, and not overly prescriptive as a first step for implementing market power mitigation of batteries, that could be refined in future stakeholder initiatives.[159]

CAISO further proposed to mitigate the entire bid curve for a battery, with the DEB applied to the full range of output, including the entire charging, and discharging range. In support of this, CAISO noted that a +/-200 MW battery could back generation down from 200 MW to 100 MW or charge at -200 MW instead of -100 MW to increase prices in local areas.[160]

Under this proposal, when computing the DEB curve for the entire operating range of the resource, when the battery is charging, the variable cost would be assumed to be zero for the entire time. This would produce a constant value for the DEB for the entire charging portion of

154 In August 2020, CAISO operated about 150 MWs of batteries, nearly all of which participated as resource adequacy capacity, the compensation for which made up a large component of the resource's total revenues. Energy storage could participate in the day-ahead and real-time markets, but the majority of the 150 MWs provided very little energy. Ibid, p. 18.

155 Additionally, possibly contributing to this outcome, CAISO considered that it was unclear whether price spreads in the electricity market are sufficient to clear any hurdle that would make it economic for these resources to shift large quantities of energy, due in part to data showing that the average maximum possible spreads to move 4 hours of energy during the day were just over $40/MWh. Ibid, p. 19.

156 Ibid p. 20.

157 Ibid.

158 In contrast to this, the SPP market allows for intra-day changes to the mitigated energy offer curve for batteries, but they must follow the Mitigated Offer Development Guidelines and be validated by the market monitor. See Southwest Power Pool, 18 May 2022, Market Protocols: SPP Integrated Market Place Revision 89. Clause 8.2.2.3, (online).

159 California ISO, 21 August 2020, *Energy storage and distributed energy resources Phase 4: Final Proposal*, p. 21, (online)

160 Ibid, p. 23.

the resource's operating range, ensuring that the DEB increased monotonically with output, consistent with the CAISO's current framework for its market solution.[161]

Advice from the CAISO Market Surveillance Committee (9 September 2020)

In response to CAISO's proposal, the Market Surveillance Committee (MSC) considered the complexities of estimating the marginal cost of batteries, and its application to determining DEBs, and concluded that opportunity costs in day-ahead and real-time markets are fundamentally different.[162]

The MSC explained that in the day-ahead optimisation, if all the relevant state-of-charge and capacity constraints are included, the cost of charging is implicitly included in the optimisation. That is, if the optimal response to increasing discharge in interval *t* is an increase in charging at an earlier interval *t*', then the market software will automatically and optimally trade off the benefit of the price received for the discharge in *t* with the cost of the price paid for the charge in *t*', adjusted for losses.[163] Therefore, the MSC concluded that there is no reason for discharge offers to include the charging price in the (day ahead) Integrated Forward Market.[164]

The MSC considered that, in real-time, the picture is muddied. This is because the cost of charging energy is theoretically irrelevant because:

> a basic principle of economics is that sunk costs are irrelevant to going-forward decisions and market-based pricing.[165]

Accordingly, the MSC noted that if a battery sells another MWh in interval *t* in real-time, it is too late to charge in a period before the binding interval, and what the charging costs were is irrelevant. The MSC concluded therefore that binding interval DEBs in the real-time markets should not include charging prices based on prices in intervals prior to *t*. Instead, DEBs in real time markets should be based on the lowest prices among future intervals including the binding interval.[166]

Regarding cycling costs, the MSC acknowledged that battery owner concerns about these costs may account for the fact that most batteries presently operating in the CAISO markets are used to provide regulation rather than energy arbitrage and that not taking account of them can make a large difference in how batteries would be used in energy. However, the MSC noted the complexities of pursuing this, given that the cost of cycling is not a constant $/MWh value and that it differs by battery type and operation.

The MSC therefore considered that more accurate approximations could be considered in the future as computational capabilities improved, and if experience with the simple $/MWh value

161 Ibid.

162 Market Surveillance Committee of the California ISO, 9 September 2020, *Opinion on Energy Storage and Distributed Energy Resources Phase 4*, p. 1, (online).

163 The earlier interval *t'* has the lowest energy price among all intervals in which additional charging is feasible (not charging at its maximum possible rate), making more energy available in *t.* Market Surveillance Committee of the California ISO (9 September 2020) *Opinion on Energy Storage and Distributed Energy Resources Phase 4*, pp. 10, (online).

164 Ibid, p. 10.

165 Market Surveillance Committee of the California ISO, 9 September 2020, *Opinion on Energy Storage and Distributed Energy Resources Phase 4*, p. 10, (online).

166 Ibid, p. 9.

resulted in highly suboptimal over- or under-cycling of batteries.[167] The MSC concluded that cycling costs are not implicitly considered in day ahead or real-time optimizations unless they are bid in, but they are a legitimate part of offers and DEBs and therefore can be included either in DEBs for charging bids, or DEBs for discharge offers in both the Integrated Forward Market and the real-time market (accounting for energy losses).[168]

Finally, in relation to opportunity costs, the MSC noted that if a market optimisation run considers all the relevant constraints for a battery, and the market's time horizon is far enough into the future to include all the likely times when the stored energy in the battery would be discharged, then the optimization implicitly weighs opportunity costs when choosing to discharge in a given interval.[169]

It is therefore not necessary to build opportunity costs into the offer. However, if the time horizon is sufficiently short, then the implicit opportunity cost in the optimization may understate the true opportunity cost. The MSC noted that, in this instance, the true cost can arise from retaining energy in storage at the end of the last interval and then selling it later when prices might be higher. Accordingly, the MSC concluded that in real-time, when time horizons are short, discharge offers need to include opportunity costs to prevent over-discharge or under-charging of storage if there is a significant probability of higher prices later in the day.[170]

Default Energy Bid Final Proposal 20 October 2020

As in its earlier publication, to apply local market power mitigation, the CAISO considered that the DEB should include the cost to purchase energy, variable operations costs of charging and discharging energy (including cycling and cell degradation costs), and an opportunity cost to ensure that the amount of energy stored by the resource is discharged in the hours with the highest price potential and not in intervals prior to this.[171] The following sections describe CAISO's consideration of each of these costs.

Energy costs

For the day ahead market, CAISO considered it critical that a value approximating the costs of energy purchased through the wholesale market be included in the DEB for batteries because, for example, if a battery purchases energy at the lowest price of the day, at \$10/MWh, it would have significantly lower costs than if it purchased energy at \$50/MWh. CAISO warned that, if energy is bought at higher costs to maintain the same price spread, sales would need to be made at higher prices.[172]

Accordingly, CAISO's updated proposal included the use of actual results from the day-ahead market to compute expected costs for purchasing energy, as if the resource were performing one cycle per day and charging during the least expensive continuous block of time during the

167 The MSC considered that as the "duck belly" deepens, it may be optimal to cycle batteries twice a day, even given the resulting shortened lifetime. Market Surveillance Committee of the California ISO, 9 September 2020, *Opinion on Energy Storage and Distributed Energy Resources Phase 4*, p. 11, (online).

168 Ibid, p. 11.

169 Ibid.

170 Ibid.

171 California ISO, 22 October 2020, *Energy storage and distributed energy resources – Storage Default Energy Bid: Final Proposal*, p. 5, (online).

172 Ibid, p. 7.

day. CAISO anticipated most resources would have four hours of storage duration, requiring just longer than four hours to charge to include round trip efficiencies.[173]

CAISO proposed that the real time market would perform differently. Here actual LMP results from the integrated forward market run for a specific day would be used to determine energy costs for battery DEBs in the real-time market.[174]

Variable operations costs

Consultation with stakeholders, indicated to the CAISO that actual operating costs for many resources that would or could potentially be built and interconnected to the system were being specifically designed to optimally perform one cycle per day, which included charging the battery once for four hours and discharging the battery for four hours later in the day. CAISO considered that procurement of resources with these capabilities was a direct result of a rule in the CAISO jurisdiction stating that resources are only able to count for resource adequacy for the energy they can provide consistently during a minimum four-hour period.[175,176]

CAISO explained that being designed to these minimum specifications, the batteries generally have a relatively consistent cost (for factors like cycle depth, ambient temperature, current rate, and average state-of-charge) while operating within their design criteria, but significantly higher costs when operating at higher levels, greater than one cycle per day.[177]

Accordingly, CAISO updated the proposed calculation for variable costs to correspond to a value that represents a battery operating beyond the specified range of performance that the resource was designed for, to be included in the DEB submitted by market participants to the CAISO for validation. As an example, CAISO considered that this might be the cost to operate a resource beyond one cycle for most of the new batteries likely to be built on the system over the next few years.[178]

Discussions with battery manufacturers and experts in developing batteries, indicated to CAISO that the anticipated costs for cycling and operating a new lithium-ion battery within its design specification (for the first cycle per day) were generally less than $30/MWh.[179] However, the costs of batteries operating beyond their design specification, were between two to three times larger than those costs when operating within them.[180]

CAISO envisioned that these costs would be submitted once and likely set for long periods of time but would have the potential to be updated when needed. CAISO did not expect that the costs associated with cycling would change much on a day-to-day basis, but that the operations and maintenance costs may adjust seasonally, with a hot summer or cooler weather.[181]

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[173] Ibid.

[174] Ibid, p. 8.

[175] Ibid.

[176] This would suggest that the early choices made regarding battery characteristics used to accredit capacity credits to this type of technology has important implications for the characteristics of the fleet that can be expected in a growing market.

[177] Ibid.

[178] California ISO, 22 October 2020, *Energy storage and distributed energy resources – Storage Default Energy Bid: Final Proposal*, p. 8, (online).

[179] Though, CAISO noted that several developers declared large differences between marginal cycling costs for different storage projects with different chemistries, and even within the same lithium-ion technology.

[180] Ibid.

[181] Ibid.

Opportunity costs

In its proposal, CAISO noted that if the market power mitigation tool replaces submitted bids with CAISO calculated DEBs in the day-ahead and real-time markets, and these bids are lower than the true cost to operate a resource, the tool may force an inefficient dispatch. CAISO argued that batteries can only generate until stored energy is depleted before needing to be recharged, so to avoid being discharged before the optimal time, a resource with limited availability should have an opportunity cost included in its DEB. CAISO considered that these opportunity costs are the value to the resource owner from not running during a particular interval and saving stored energy until a later time when prices are higher.[182]

As a simple example, CAISO offered that, in the real time market, if the battery has a DEB of $60/MWh and is fully charged, and the current market price is $75/MWh, it would be profitable for the resource to discharge and receive this revenue. However, the decision to discharge may be sub-optimal, as prices in the successive four hours rise to $100/MWh, and the battery should optimally wait to discharge stored energy, until the later hours when prices are higher. CAISO considered that, in this example, an opportunity cost increasing the total DEB to $100/MWh would be appropriate for this resource.[183]

As noted by CAISO, the inclusion of opportunity costs in the DEB is more complicated when a resource can buy and sell energy for multiple hours, and buys or sells energy in the real-time market, experiencing economic losses. CAISO therefore proposed including the highest price corresponding with the storage duration of the battery in its DEBs (e.g., if the battery can store four hours of energy, the opportunity cost included in the real-time DEB would be equal to the estimated prices in the fourth highest hours of the day from the day-ahead market.[184]

Energy storage enhancements: revised straw proposal (9 March 2022)

In 2022, following implementation of the earlier proposal, and with just over 2,600 MW of batteries now installed in the CAISO market, CAISO released a revised proposal to address concerns raised by stakeholders about a lack of compensation during critical periods when the ISO retained state of charge on batteries, precluding participation in the real-time markets.[185]

As explained by CAISO, the existing bid cost recovery rules were designed based on traditional generation resources and did not consider energy storage charging and discharging cycles. A primary objective of this new initiative was thus to develop solutions to enhance the optimisation of batteries and allow additional flexibility for storage operators to manage state of charge in real-time markets. CAISO proposed a new model, called the Energy Storage Resource (ESR) model, which was unique from existing models because bids were predicated on incremental state of charge (SOC) values, rather than the traditional dispatch instruction for incremental energy.[186]

The ESR model would require batteries to bid two independent bid curves covering the same operating SOC range, one specific to charging and the other specific to discharging, with up to a total of 10 segments and spanning a SOC range from a minimum state of charge to a

[182] Ibid, p. 9.

[183] Ibid, pp. 9-10.

[184] Ibid, p. 10.

[185] California ISO, 9 March 2022, *Energy Storage Enhancements: Revised Straw Proposal*, p. 3, (online).

[186] Ibid, p. 4.

maximum state of charge.[187] CAISO considered that this model will allow batteries to reflect the different incremental costs associated with the different levels of state of charge, with a battery able to offer lower prices to provide energy when it has a nearly full state of charge and higher prices when it is nearly depleted. Based on the cost reflected in its charging and discharging bid curves, a battery would be scheduled to charge, discharge, or remain at the same state of charge.

CAISO proposed a DEB for batteries electing to participate in this new model to include the cost for batteries to buy energy, cycling costs, and opportunity costs to charge resources and additional opportunity costs of a depleting state of charge.[188] The estimated cost to charge was calculated in the same way as in the earlier model, with costs estimated from the mitigation run of the market used to estimate prices, and CAISO assuming that storage is fully charging from 0 MWh (the minimum state of charge) to its full state of charge during the lowest priced contiguous block of hourly prices that day.[189] As an example, noting that a typical four-hour duration battery takes just over four hours to charge (considering round-trip efficiencies), CAISO considered that it would use the associated prices from these hours to determine an estimate for charging costs for the resource.

CAISO noted that the estimates for these prices may be conservative, as batteries may not be scheduled to completely charge in the day-ahead market, but instead may be scheduled to charge in the real-time market when prices are even lower than expected prices in the day-ahead market. Additionally, the prices may be at lower levels in the integrated forward market run of the day-ahead market than what was anticipated in the mitigation run.[190]

CAISO planned to use a similar process to determine estimated costs for charging batteries using finalized values established from the day-ahead market from the integrated forward market run to feed into the DEB.[191]

CAISO also proposed a similar process for cycling costs for batteries as in the previous model. Noting that it understood that batteries can have higher costs for cycling beyond the normal operating designs, CAISO anticipated developing a conservative approach to estimating the value for cycling costs, and that it would continue to use the upper bound for cycling costs in calculating the DEB for resources using the ESR model.[192]

CAISO considered that the primary purpose of its new model was to provide transparency of the increasing value of energy, as the state of charge of a battery decreased. In line with this, CAISO intended to ensure that the DEB for the discharge portion of the bid curve in the real-time market increased as the state of charge decreased.[193]

Accordingly, CAISO proposed to use prices from the integrated forward market run of the day-ahead market to determine this slope, as the average of the highest priced hour of the day and the n^{th} highest priced hour of the day, with n corresponding to the duration of the battery.[194]

187 CAISO considered that the gap between the two bid curves "could be used to represent a 'spread,' or the difference between a price the resource would be willing to charge at and the price the resource would be willing to discharge at." Ibid, p. 10.

188 Ibid, p. 14.

189 CAISO proposed to cap this value at 8-hours, even for extra-long duration batteries.

190 Ibid.

191 California ISO, 9 March 2022, *Energy Storage Enhancements: Revised Straw Proposal*, p. 14, (online).

192 Ibid.

193 Ibid.

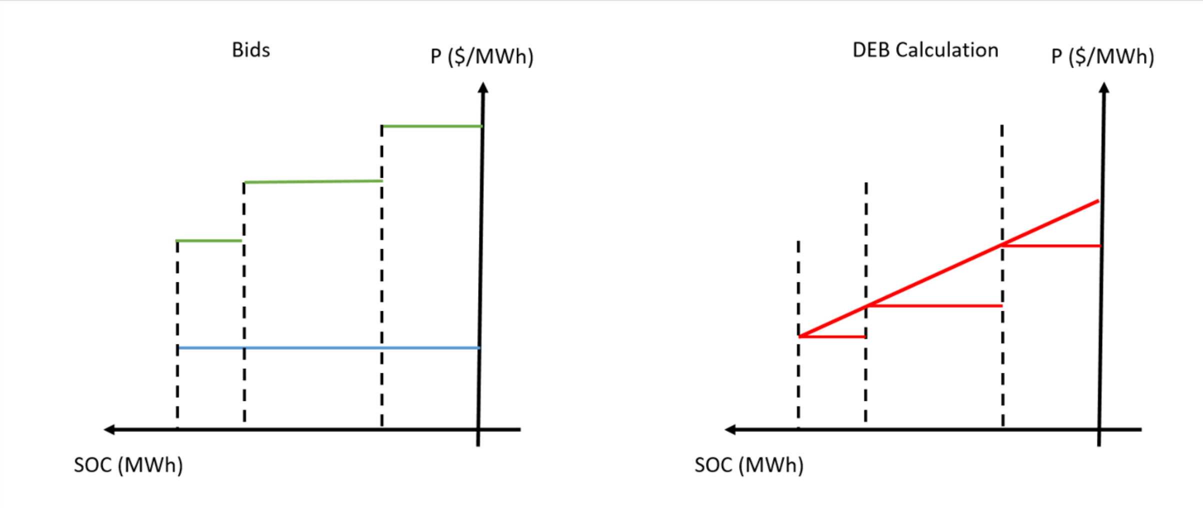
194 For example, for a 4-hour duration battery, n = 4.

$$\textbf{DEB slope} = (\textbf{Highest continuous price for the battery duration} - \textbf{lowest continuous price for the battery duration}) \div \textbf{the battery duration}$$ [195]

The use of the DEB slope contrasts with CAISO's previous use of segments with constant prices and slopes equal to zero.

CAISO proposed to use the same concept to apply to DEBs for the batteries, with the quantity (MWh) segments of the bid curves specified by the bids from the resource and the $/MWh value the DEB curve derived from the slope specified in the same way. CAISO's proposal provides an illustrated example, which is represented in Figure 8 and Figure 9 below.[196]

Figure 8: CAISO's sloped DEB calculations

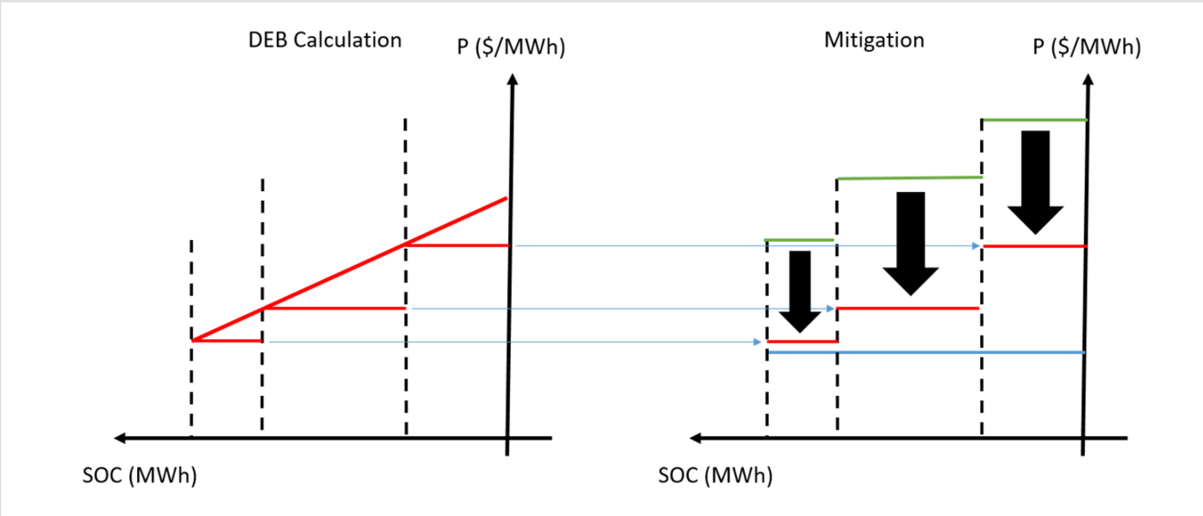


Source: California ISO, 9 March 2022, Energy Storage Enhancements: Revised Straw Proposal, Figure 4, p. 15.

195 For example, for a four-hour duration battery, if the highest continuous prices are: $60/MWh, $70/MWh, $80/MWh and $100/MWh, the DEB slope = ($100/MWh - $60/MWh)/4 hours = $10/MWh. California ISO, 11 February 2022, *Energy Storage Enhancements – Energy Storage Model and Market Power Mitigation*, p. 5, (online).

196 Ibid, pp. 14-15.

Figure 9: Mitigation of bids using CAISO's sloped DEB



Source: California ISO, 9 March 2022, Energy Storage Enhancements: Revised Straw Proposal. Figure 5, p. 16.

Where a scheduling coordinator of a battery bids three discharging segments into the market for the resource. This results in three segments of the DEB, represented in Figure 9. To determine the DEBs for batteries, CAISO will:

1. Estimate the cost for the battery to buy energy and add the cycling costs to that value'
2. Compare this value to the opportunity cost and use the greater value to set the leftmost point of the sloped red curve in Figure 8 and Figure 9.
3. Determine the slope using the above formula and apply that from the leftmost point of the SOC axis.
4. Determine the DEB segments as the intersection of the start of the bid segment (left limit of bid) and the diagonal red line.
5. If market power mitigation is required, the DEB will be used in lieu of any bid curves that are higher.[197]

CAISO's Business Practice Manual for Market Operations notes that it will not optimise state of charge for hybrid resources, but they will still be required to submit this information to the CAISO along with other telemetered values.[198]

Calculating the SRMC of multiple technology facilities

The SRMC of multiple technology facilities may be difficult for a third party (i.e., a regulator) to establish independently. A hybrid or co-located resource's estimation of its own opportunity cost will depend on complex modelling assumptions, considering the output of the co-located

197 California ISO, 9 March 2022, *Energy Storage Enhancements: Revised Straw Proposal*, p. 15, (online).

198 California ISO, Business Practice Manual Change Management BPM_for_Market_Operations_Version 81_Redline, Revised 1 June 2022, p. 88, (online) [accessed 24 June 2022).

VER resource, expectations of future energy prices, and the relative compensation, including non-ISO revenues, it will receive from providing different services.[199]

Forecasts of opportunity costs will likely differ from the default opportunity cost calculations described above for standalone resources, most of which were based in part on energy price forecasts. It may be the case that in the WEM, the opportunity costs will need to be determined differently for different resources and submitted to the regulator for approval, as already occurs in other jurisdictions.

As explained by the American Wind Energy Association (AWEA), the wait and see approach taken by CAISO may, in the first instance, be considered for application in the WEM, because:

- If a resource lacks market power, it has no incentive to withhold physically or economically, as it is not profitable.
- As noted in relation to CAISO, batteries have an incentive to reduce cycling costs, which they achieve through providing regulation ancillary services. They only provide energy in the day-ahead or real-time market when prices are high.
- The limited duration of the battery resource may interfere with market power strategies. Batteries charged onsite from solar PV generally have an incentive to inject into the energy market only when it is most valuable to the system. However, they may elect to discharge during low priced hours, if necessary, to create the capability to store solar generation in subsequent periods, comply with capacity supply obligations, or create the capability to provide ancillary services. It cannot simply be assumed that hybrid resource batteries will be used to smooth out variability (relative to forecasts) of solar PV, as it may harm the resource’s ability to meet its forecast in the subsequent hours of the day (e.g., at system peak).
- Other revenue streams available to resources make it less likely batteries will withhold capacity:
  - In the US, other revenue streams include incentive programs, such as the Investment Tax Credit (ITC), which is a federal income tax credit for renewable energy projects, including fuel cells. Owners of qualifying projects claim tax credit up to 30per cent of capital costs. To qualify, at least 75 percent of the energy used to charge battery must come from the PV array. A hybrid or co-located resource can only capture the full value of the ITC if the battery charges 100per cent from its associated Solar PV array. As such, the optimal use of hybrids and co-located resources may not involve charging from grid at all.[200]
  - PPA’s may make it less likely that resources will withhold capacity. Selling power on a forward basis generally makes a seller less sensitive to market clearing prices. A standalone or component of a hybrid or co-located resource may be less exposed to the market price compared to resources that have not sold their output forward in the bilateral market.

[199] American Wind Energy Association, September 2020, *Hybrid and co-located resource market power mitigation: An examination of the applicability of current ISO/RTO mitigation provisions to hybrid and co-located resources*, p. 21, (online).

[200] Another tax credit in the US is the Production Tax Credit (PTC), which is a per kilowatt-hour (kWh) federal tax credit for electricity generated by qualified renewable energy resources. See: United States Environmental Protection Agency website, Renewable Electricity Production Tax Credit Information, (online) [accessed 30 June 2022].

Appendix 7 Report from consultant: Endgame Economics

ENDGAME
ECONOMICS

BARRIERS TO EFFICIENT PRIVATE INVESTMENT IN THE WEM

A Report for The Economic Regulation Authority of Western Australia

11 July 2022

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0. Executive Summary

Endgame Economics ('Endgame') has been engaged by the Economic Regulation Authority ('ERA') to identify whether barriers to efficient investment exist in the Wholesale Electricity Market ('WEM'). Where found, Endgame should provide options to address these barriers to support the WEM to meet both its objectives and the State Government's policy goals for the South West Interconnected System ('SWIS').

0.1.1. Nature of this report

The barriers that Endgame has been commissioned to investigate occur in the following areas:

- Market features that slow the pace of entry of new low-emission technologies and batteries while deferring the exit of high emission technologies (i.e., the revenue sufficiency challenge for new entrants);
- Price signals that provide incentives for investments at the expense of higher costs to parties in other areas of the network (i.e., the locational signals barrier); and
- Any other barriers inhibiting efficient investment.

0.1.2. Our method

To assess the *materiality* of these barriers, we have conducted research and modelling that investigates:

- The significance of each barrier in affecting the WEM objectives within the context of the State Government's policy goals for the WEM and net zero.
- The conditions and/or timings for the emergence of these barriers.
- Potential solutions that could address these barriers.

Specifically, we have built two models:

- Firstly, a model to assess the effect of the large uptake of variable renewable energy ('VRE') leading to revenue reductions for all solar and wind farms (revenue cannibalisation) in the WEM. As part of this modelling, we also investigate how the absence of a carbon price reconciles with the assumption that emissions targets are met.
- Secondly, a nodal model to assess the impact of locational pricing (which reflects the value of energy at different parts of the network) in leading to more efficient price signals (than zonal pricing) for generation investment.

We have also prepared an inter-jurisdictional review that discusses existing regulatory market arrangements of other international jurisdictions in addressing the two barriers identified above.

Lastly, we have considered the Network Access Quantity ('NAQ') framework and its impact on locational investment signals. In doing so, we have undertaken analysis to assess the materiality of the NAQ constraining the low-cost VRE entry into the market.

0.1.3. Summary of recommendations

An additional mechanism might be required to support revenue sufficiency for VRE

The purpose of the project was to demonstrate two dynamics: first, the relationship between increasing penetration of renewables and the cannibalisation of energy market revenue, and second, the shortfall of revenue that emerges when we assume build occurs subject to a carbon constraint, but that no carbon price exists in reality. Our model has shown that prices in the WEM under existing arrangements are not high enough to support revenue sufficiency for wind, solar and batteries, and that the extent of this revenue insufficiency expands with the increasing penetration of renewables (as the marginal generator increasingly becomes VRE facilities which bid in at their short-run marginal cost) – see section 3.3.2. Low market prices, in turn, may reduce facilities' financial viability to maintain or expand their investment and may compromise the WEM's ability to reach net zero by 2050. Accordingly, additional mechanisms may be required to support the revenue sufficiency for private VRE participants.

An important component of the exercise is that we have not explicitly modelled capacity payments, nor have we included revenue from Essential System Services ('ESS'). Instead, we have demonstrated the disconnect between planning a system with a carbon constraint, and then not imposing a carbon price. The interpretation of our results is that the shortfall in *energy* revenue must be made up by some other payment to deliver the plan that is formed on the basis of there being a carbon constraint. Our analysis shows that capacity payments at the current level are not sufficient to make up the shortfall entirely for VRE. In contrast, an argument can be made that ESS will adequately remunerate batteries in the early stages of the transition to low emissions. Further thinking needs to be done about the interplay between these different factors.

It is our understanding that, as part of WA's Energy Transformation Strategy, energy and essential system services will be co-optimised through the Security-Constrained Economic Dispatch ('SCED'). This should work to improve dispatch optimality and produce more efficient price signals as it manufactures a trade-off for reserve shortfalls between energy and essential system services (as in the NEM) – see section 2.1.1. A more efficient pricing outcome should also assist with reducing revenue insufficiency problems. Nevertheless, the SCED alone is unlikely to address revenue adequacy issues for VRE given the scale of identified shortfalls.

In general, there are three options for addressing the revenue adequacy issue in the WEM including lifting the MPC, adjusting capacity payments or introducing additional revenue streams to reflect the value of the "missing carbon market".

Our modelling has demonstrated that VRE entrants will generally be able to recover their costs when the cost for emissions abatement is explicitly priced. This in turn would enable and advance the WEM's ability to achieve net zero emissions by 2050. Although we modelled carbon revenue through a generic carbon constraint, in practice this could be implemented via different policy instruments including pricing emissions, tradable emission schemes, or direct, targeted subsidies to renewable plants coupled with the coordinated exit of the existing thermal fleets.

We do not recommend locational pricing at this stage but the ERA should continue to monitor generation and transmission development in the WEM

While the barrier of inefficient locational price signals generated through a zonal price setting is not as pressing as the revenue sufficiency challenge described above, our nodal model has shown that there could be material price separations across different locations in the SWIS system. This suggests that a single zonal price will be less efficient (i.e., less reflective of the value of energy at different locations) than full locational marginal pricing (LMP).

Nevertheless, we do not recommend that the ERA introduce nodal pricing into the WEM at this stage. The reasons being the following:

- Nodal pricing creates additional price volatilities in thinly meshed networks that are prone to congestion (such as the SWIS).
- The implementation of nodal pricing is often a large-scale reform, which could involve major changes in various aspects of the market process.
- In practices, the WEM already has, or will soon introduce other mechanisms for managing congestions in the form of SCED and the NAQ framework.
- Targeted system-wide planning, supported by rigorous engineering and market studies, could offer a viable alternative to pure price signals as a mechanism to coordinate generation investments.

We do, however, recommend that the ERA continue to monitor the development of generation investment and the resultant impact on network congestion in the SWIS in the coming years.

1. Introduction

This engagement explores the materiality (i.e., the significance, timing and conditions) of two 'inhibiting' factors for timely and efficient private investment in the WEM. These are:

- Market features that slow the pace of entry of new low-emission technologies and batteries while deferring the exit of high emission technologies (i.e., the revenue sufficiency challenge for new entrants); and
- Price signals that incentivise investments at the expense of higher costs to parties in other areas of the network (i.e., the locational signals barrier).

It is our understanding that the first point above is a particularly crucial issue for the ERA given the federal labour government's announced target to reach net zero by 2050. We briefly discuss the scope of each of these points in turn below.

Revenue sufficiency

Revenue sufficiency refers to the extent to which a generation or storage facility is able to earn enough revenue from the market to recover its capital and operating costs. Provided the facility's revenue is sufficient, it would have the ability to remain in the market and/or justify investment in new capacity. These facilities, in turn, are required to provide sufficient capacity to meet demand and to support system reliability.

New VRE entrants with near-zero marginal costs generate revenue sufficiency challenges for both themselves and other facilities, as these facilities dampen the energy market clearing prices. In turn, low energy market prices may reduce facilities' financial viability to maintain or expand their investment. We have built a model to assess the effect of the cannibalisation of revenue associated with the uptake in renewables in the WEM. We also investigate the impact of a carbon price on revenue adequacy.

Locational signals

The WEM employs zonal pricing where the settlement process is based on a single price at a specific part of the network – the regional reference node (i.e., currently the Southern Terminal). All generator facilities that participate in the market are subject to this price regardless of where they locate. The issue, though, is that the value of energy varies at different parts of the network due to congestion and losses. Congestion is primarily caused by a lack of transmission capacity to support the supply of electricity in meeting demand, and it may rise in line with higher renewable penetration given the non-dispatchable nature of VRE. Accordingly, zonal pricing arguably functions as an inefficient price signal for generation investment.

Locational marginal pricing (LMP), on the other hand, refers to the approach where prices reflect the value of energy at different locations. Unlike zonal pricing, LMPs capture the costs of congestion and so prices vary at different nodes. In particular, prices will be low where local congestion prevents generation exports to other parts of the network. In an ideal world, this would send signals for generation investment - generators are incentivised to locate at nodes where prices are high (i.e., less congested areas). It follows that in an ideal setting, LMPs would reduce the total cost of supply energy and will be a more economically efficient outcome.

We have built a linearised DC power flow model to assess the extent of locational price variation in the WEM. Everything else held constant, greater price variations across different location means that LMP will send stronger locational price signals to participants.

Notwithstanding, LMP can also create additional price volatilities in long networks that are prone to congestions, such as the SWIS. This could introduce additional uncertainties for new entrants. In addition, the implementation of the LMP is often a large-scale reform which could involve major changes in various aspects of the market process such as dispatch (including the underlying dispatch engine), pricing and settlement. Additional financial instruments might also be needed to help participants mitigate locational price risks. In practice, there are alternative mechanisms for managing congestions at both operational and investment timeframes, such as the SCED and the NAQ framework. While not pricing signals, they can provide adequate congestion management in practice and better balance the potential benefit and cost of regulatory reforms.

NAQ framework

Under the incoming constrained network access model, facilities do not have an inherent or guaranteed level of access to the network, including during peak demand periods. Incumbent facilities face the risk of being displaced by new entrant facilities connecting to constrained parts of the network. The NAQ framework is being implemented to prevent this.

While the NAQ framework should work to prevent this from eventuating, it invariably produces another inefficient outcome by reducing the ability of lower cost new entrants to gain Capacity Credits until capacity becomes available.

We have provided a qualitative assessment of the materiality of the NAQ as a barrier to efficient locational outcomes (i.e., in constraining low-cost VRE entry into the market).

Inter-jurisdictional review

To supplement our quantitative analysis of the revenue sufficiency and locational signals barriers, we have also provided an inter-jurisdictional review of these issues. Specifically, this looks at existing regulatory arrangements and interventions to manage these two issues in other international jurisdictions.

Structure of this document

The remainder of this document is structured as follows:

- **Section 2** details our inter-jurisdictional review of the locational signals and revenue sufficiency barriers.
- **Section 3** describes the methodology, assumptions, findings and recommended options from our nodal model to investigate the revenue sufficiency challenge.
- **Section 4** describes the methodology, assumptions, findings and recommended options from our model to investigate the locational signals barrier.
- **Section 5** sets out our qualitative assessment of the materiality of the NAQ framework as a barrier to efficient locational outcomes.

2. Inter-jurisdictional analysis

This review firstly discusses existing regulatory market arrangements of other international jurisidictions in relation to:

- Creating opportunities for facilities with renewable technologies to earn sufficient revenue, i.e., policies aimed at compensating generators who provide services that are otherwise not explicitly incentivised.
- Supporting efficient locational decisions for generation facilities, i.e., by establishing price signals and/or other market mechanisms to influence these facilities to locate in network areas where there is sufficient export capacity.

Secondly, this review should serve to inform the ERA of potential market interventions that could be implemented to ensure revenue sufficiency for facilities in the WEM.

Selected markets

The jurisdictions that we have reviewed include:

- **The Electric Reliability Council of Texas** – ERCOT is one of eight independent system operators in North America and serves 26 million customers in Texas, approximately 90 per cent of the state[1]. ERCOT is an energy-only market that manages 85,000km of transmission and over 1,030 generation units, which produce 429,800 GWh per year[2].
- **The Pennsylvania-New Jersey-Maryland Interconnection** – PJM is one of the largest energy markets in the world, serving 13 regions in the Mid-Atlantic and Great Lake areas of the United States, which includes more than 65 million customers. It is a capacity market services 140,000 km of transmission lines and 1,379 generators, which annually produce 773,522 GWh of energy.
- **The Australian National Energy Market** – The NEM services approximately 10 million customers per year in Queensland, New South Wales, Victoria, South Australia and Tasmania. It is an energy-only market that incorporates 40,000km of transmission lines and connects 200 market participants supplying 200,000 GWh of electricity each year[3].
- **The New Zealand Energy Market** – the NZEM is an energy-only market operated by the Electricity Authority (EA). The EA services all customers in New Zealand including 12,000km of transmission lines, 170 substations and 5 major generators amounting to 40,000 GWh of energy per year[4].
- **The Midcontinent Independent System Operator –** MISO is an independent organisation responsible for operating the power grid across 15 US states and the Canadian province of Manitoba. It operates as a capacity market.

We have chosen to review these markets because they share similar market, operational characteristics, conditions and / or future trajectories to the WEM.

[1] https://www.ercot.com/about
[2] https://www.energy.gov/sites/prod/files/2016/09/f33/TX_Energy%20Sector%20Risk%20Profile.pdf
[3] https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/about-the-national-electricity-market-nem
[4] https://www.ea.govt.nz/operations/transmission/about-transmission/#:~:text=New%20Zealand's%20transmission%20system%20is,and%20more%20than%20170%20substations.

2.1. Revenue sufficiency

2.1.1. The National Electricity Market (NEM)

Co-optimisation of energy and ancillary services in the NEM supports revenue sufficiency for facilities. It does so by tightening the trade-off between energy and ancillary services that compete for the same reserve capacity. This in turn provides more efficient price signals. Critically, there is an upward pressure on both energy and ancillary services market clearing prices when there is a shortage in one of the them (or both).

Facilities are required to submit their energy and ancillary quantities, and their associated offered prices for these services for market clearing. The NEM Dispatch Engine (NEMDE) then jointly determines the least-cost way to dispatch both energy and ancillary products with respect to system operation constraints. This is typically done as a single optimisation and accounts for information relating to outages, network constraints, load forecasts and renewable generation forecasts.

The NEM also has an MPC of AUD15,100/MWh (reviewed periodically by the Reliability Panel in its Reliability Standard and Settings Review), which allows energy and ancillary services prices to greatly surpass facilities' variable costs when the system is capacity constrained.

The MPC has been a subject of debate ever since the start of the NEM. Indeed a capacity mechaism is being considered as an alternative measure to support revenue sufficiency. Atlhough this discussion mainly concerns dispatchable capacity, it has raised important questions about revenue adequacy for renewables in an increasingly higher VRE penetration world.

2.1.2. The Electric Reliability Council of Texas (ERCOT)

ERCOT addresses the revenue sufficiency challenge through a form of scarcity pricing. Specifically, it seeks to artificially lift average energy prices through an operating reserve product. The reserve product is effectively surplus operating capacity that can instantly respond to a sudden disruption in output or increase in load.

The value of reserve capacity is governed by the Operating Reserve Demand Curve (ORDC). This is a continuous demand function that represents the risk of a shortage of operating reserves[5]. It is based on a probabilistic assessment of the contribution of reserves towards system reliability. That is, the ORDC determines the value of reserve capacity based on the hourly Loss of Load Probability (LOLP) of an outage occurrence and the impact of an outage on consumers, i.e., the Value of Lost load (VOLL).

Here, wholesale prices in the real-time energy market automatically adjust with the availability of operating reserve. That is, as reserve levels fall and the LOLP increases, the marginal value of reserve capacity increases, as does the market price. Should reserves fall to a minimum contingency level of 3,000 MW (previously 2,000 MW) or less, the ORDC sets the market price to the VOLL at a cap of USD 5,000 / MWh (previously USD 9,000 / MWh)[6]. In contrast, an increase in reserve levels would lead to a decrease in the market price.

[5] https://www.nrel.gov/docs/fy17osti/66935.pdf
[6] https://www.enverus.com/blog/ercot-volatility-how-are-the-ordc-changes-impacting-the-market/

The ORDC, in effect then, functions as a price adder to wholesale prices in the real-time market. The possibility of implementing an operating reserve product is a discussion that has been held recently in the NEM.

2.1.3. The Pennsylvania-New Jersey-Maryland Interconnection (PJM)

The revenue sufficiency challenge in PJM is addressed through its forward capacity market (CM) with a locational element. The CM assesses whether enough capacity will be installed and available to meet load in peak periods. It then provides incentives for new capacity to be built in locations where it is most needed.

Required reserve margins are determined by comparing peak load forecasts on a weekly level, with seasonal derated capacities and historical performance data of existing facilities. Importantly, derating methodologies vary by resource type. For VRE, derating is based off a facility's Effective Load Carrying Capability (ELCC), which simulates the completely firm generation that a unit can replace, while maintaining the same reliability standard, based on historical data on weather patterns, load shapes and output patterns[7].

Following this, PJM then procures capacity by allocating contracts through an auction process. There are several auctions, starting with the Base Residual Auction at T-3 and then followed by incremental auctions at 20, 10 and 3 months before the capacity is required. Auctions are cleared to minimise cost, and facilities receive the clearing price for the whole of PJM plus a locational price adder for their local delivery area.

Following the initial auction process, facilities can then engage in certificate trading to buy or sell capacity from another capacity provider, from the system operator or through ongoing bilateral contracts[8].

PJM also has an administratively set cap on wholesale energy price offers set to USD1,000/MWh. Though, bidders can offer up to USD2,000/MWh[9] if they can provide a cost-based reason for an offer above USD1,000/MWh.

2.1.4. The Midcontinent Independent System Operator (MISO)

MISO firstly relies on cost of services regulation to ensure revenue sufficiency. Specifically, it issues Revenue Sufficiency Guarantee (RSG) make whole payments to ensure that the revenue of a committed facility is at least equal to its as-offered costs over a pre-defined commitment period. RSG payments can appear in both the day-ahead and real-time settlement.

We note, though, that RSG payments are a complicated and contentious mechanism. Some argue, for example, that guarantee payments can distort price outcomes and influence inefficient signals to participants.

Secondly, MISO administers a voluntary capacity market (CM) to compensate resources for meeting resource adequacy. Local clearing requirements are determined by MISO for each of the ten zones within its jurisdiction, which are then met through an annual Planning Resource Auction (PRA)[10]. This allows facilities to buy and sell capacity. Zones can also import and export

[7] ESB CM Design Draft Paper
[8] ESB CM Design Draft Paper
[9] https://www.osti.gov/servlets/purl/1247648

[10] https://www.misoenergy.org/planning/resource-adequacy/#t=10&p=0&s=FileName&sd=desc

capacity to meet their local clearing requirements, subject to transmission and contractual limitations.

However, the true value of capacity for generators is arguably diluted in the CM due to the way demand for capacity is represented. Demand is modelled as a single quantity value (i.e., a vertical demand curve for the market) rather than a typical sloped demand curve. It was designed this way to satisfy MISO's minimum planning reserve requirements with the price capped at a deficiency price based on the cost of building a new resource. This means that each marginal contribution of surplus capacity generates no additional value for the system, which is an unrealistic reflection of capacity.

Similar to the other markets in review, MISO has an administratively set price cap of USD3,500/MWh[11].

2.2. Locational signals

2.2.1. The Electric Reliability Council of Texas (ERCOT)

Currently, ERCOT supports efficient locational decisions through nodal pricing. Unlike zonal pricing, this setting gives rise to locational price signals that reflect actual congestion conditions (as well as other external locational costs, such as transmission losses). Prices will therefore reflect the value of energy at different locations across the network. Subsequently, generators are incentivised to locate at nodes where prices are high.

Nodal pricing should alleviate congestion as the last marginal entrant would make the decision to not enter or build at an already crowded node that is subject to lower prices.

Interestingly, only generators and transmission facilities are subject to nodal pricing in the ERCOT design since their revenue is calculated at the respective injection node. In other markets, it is also common for customers to be impacted by nodal pricing as well. Instead, here, customers are subject to zonal pricing, which is a load-weighted average of the LMPs[12].

Prior to implementing nodal pricing, ERCOT managed its high intra-zonal congestion through Out-Of-Merit Order settlements[13]. This refers to the arrangement in which generating units can be dispatched out of the economic merit order to maintain transmission flows within the appropriate range, i.e., expensive generators could be dispatched ahead of cheaper ones – which is clearly an inefficient price signal.

2.2.2. The Pennsylvania-New Jersey-Maryland Interconnection (PJM)

PJM also uses locational marginal pricing to support efficient locational decisions. However, unlike the case in ERCOT, both generators and customers are subject to their respective local node, i.e., generators submit their bids at the injection node level to which demand is then priced and cleared[14].

As described in section 1, LMPs can become very volatile and as a result may even deter investment if a facility expects to frequently receive a low LMP. To manage these locational

[11] https://www.osti.gov/servlets/purl/1247648
[12] http://www.puc.texas.gov/industry/electric/reports/31600/puct_cba_report_final.pdf
[13] http://www.puc.texas.gov/industry/electric/reports/31600/puct_cba_report_final.pdf
[14] https://www.pjm.com/-/media/training/nerc-certifications/markets-exam-materials/mkt-optimization-wkshp/locational-marginal-pricing-components.ashx

price risks, the operator introduced Financial Transmission Rights (FTRs) to the market[15]. These are essentially financial instruments that entitle the holders (which are usually generators) to the difference between LMPs at two different nodes.

We note, this is also how congestion is managed in the New Zealand Electricity Market.

2.2.3. The National Electricity Market (NEM)

Unlike other markets, the NEM has not implemented locational marginal pricing. Rather, AEMO manages congestion by adjusting constraint equations to the NEM dispatch engine. That is, AEMO can adjust constraints to control power flows by 'constraining-on' or 'constraining-off' certain generators[16]. A generator is constrained-on when it is dispatched for a quantity that is greater than the amount it is willing to produce, while a constrained-off generator is dispatched for a quantity that is less than the amount it is willing to produce.

Congestion is also alleviated through the application of marginal loss factors (MLFs). MLFs capture the relationship between a generator's output and the amount of energy that they provide to the system after adjustment for losses. In the NEM, a generator's revenue is adjusted for their marginal loss factor, such that the revenue of a generator who is located in a congested part of the network will decrease proportionately more than the revenue of a generator located in a non-congested part of the network. We note, most energy markets have adopted MLFs or a similar concept to account for losses caused by congestion.

Lastly, the Energy Security Board (ESB) is currently exploring additional options to further address concerns relating to excess congestion – one of which is a Congestion Management Mechanism (CMM). Under this approach, congestion charges would be issued to generators that contribute to congestion while generators who locate in parts of the network that have spare capacity (particularly Renewable Energy Zones) would receive a rebate.

[15] https://learn.pjm.com/three-priorities/buying-and-selling-energy/ftr-faqs.aspx

[16] https://www.aemc.gov.au/sites/default/files/content/42a1dfd9-bf32-4bf1-bcc4-81dd8095dfc7/Final-Report-Appendix-A-An-introduction-to-congestion-in-the-NEM.PDFcongestion management

3. Revenue sufficiency model

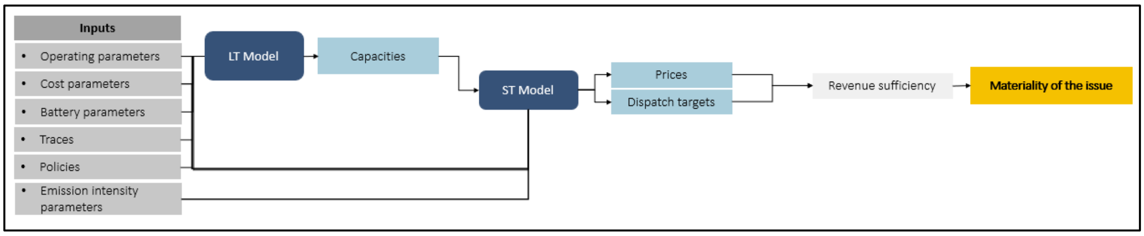
This section describes the methodology, assumptions and findings from our revenue sufficiency model. The model allows us to demonstrate the materiality (i.e., significance, timing, conditions, recommendations) of:

- How the increased uptake of VRE dampens energy prices and reduces incentives for further VRE entry; and
- How an explicit carbon price changes this outcome, and how accounting for emission constraints (or put alternatively, how accounting for emissions costs) changes this outcome.

3.1. Methodology

We built a bespoke, least-cost optimisation model that incorporates both a long-term (LT) planning component and a short-term (ST) dispatch component – see Figure 1.

Figure 1 - Overarching methodology for revenue sufficiency model



Long-term planning model

The LT component determined the generation mix of generation technologies in the WEM - It established which generation technologies should enter and retire from the market on a least-cost basis while meeting a given level of demand and a carbon emissions target.

The model was firstly run to create a baseline scenario where the carbon emissions constraint was excluded. This enabled us to determine the optimal fuel capacities for a world where we are not concerned with emissions. Following this, we ran the model at progressively tighter emissions targets (where emissions are set at a percentage of the baseline scenario) by 10% increments until a target of net zero emissions. In conjunction with offer prices and quantities, the capacities built in the LT model were fed into the ST component

Short-term dispatch model

The ST determined optimal dispatch outcomes at different levels of renewable uptake (derived from the LT model described above) on a least-cost basis. The model was run for each of the emissions targets established above.

The model was run against two scenarios: one where prices include a carbon component, and one where they do not, such that prices exclude emission costs.

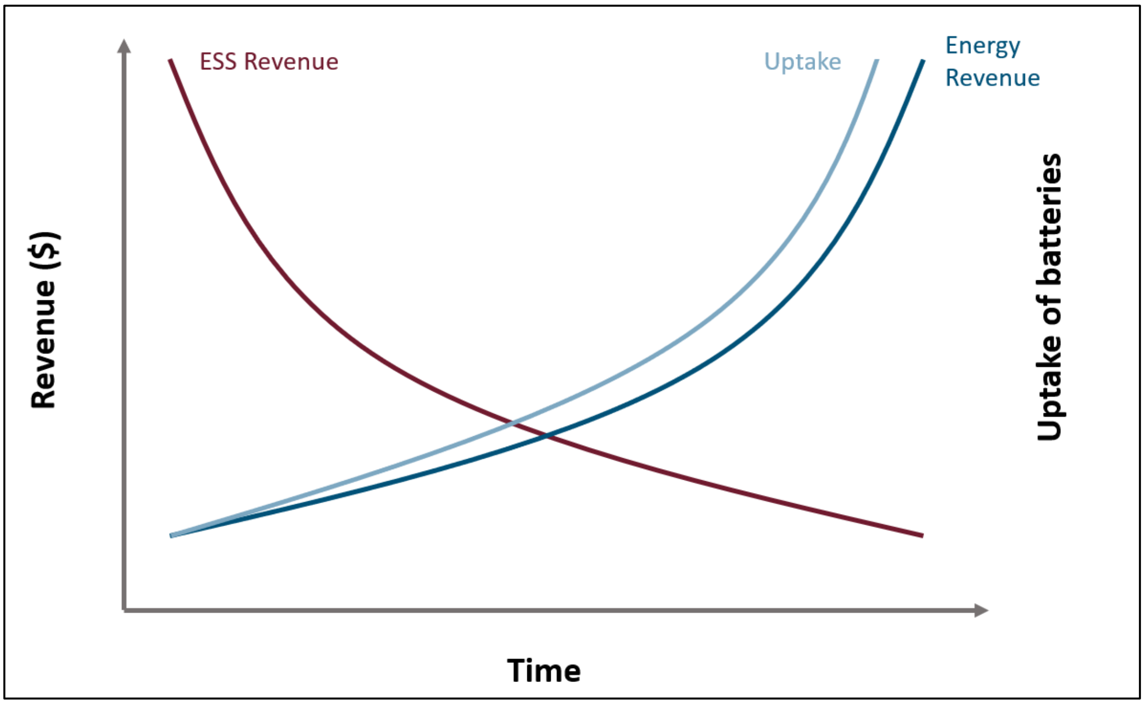
A simplified representation of the WEM market process

Our model focuses on energy market revenue and hence is a simplified representation of the WEM market process. As the effect of revenue cannibalisation is primarily felt in the energy market, we have not included the capacity market, ancillary service markets and their associated revenue in our analysis.

We have not explicitly included capacity payments within the model, but using the outputs of the model we have compared any revenue shortfall with values that are consistent with those arising from the Relevant Level Methodology. These values were based on the reserve capacity price for transitional facilities multiplied by a capacity factor (0.3 for wind and 0.2 for solar, based on the traces that were used for the study). This resulted in capacity payments of around $35,600/(MW.year) for wind and $23,700/ (MW.year) for solar. Our analysis shows that these values are insufficient to make up for the revenue shortfall when there is no carbon pricing regime in place. This suggests that some additional value stream would be required to deliver the build profile that satisfies the carbon constraint.

Though we expect the majority of battery revenue to be driven by ESS in the short-term, we have not included this market in our analysis as battery market saturation will likely lead to a significant reduction in the marginal ESS revenue per battery in the long-term. Additionally, we would expect battery energy revenues to rise and displace ESS revenues over time, such that ESS revenue could become insignificant - see Figure 2 below.

Figure 2 - Change in ESS and energy revenues over time



This is a dynamic that has begun to transpire in the NEM with the entry of The Hornsdale Power Reserve and The Victorian Big Battery. Additionally, the ESS market has a relatively minor impact on VRE, given these facilities generally do not earn payments from these markets.

Our modelling results show the relative change in energy market revenue - as revenue cannibalisation intensifies with greater VRE penetration, the gap between energy market revenue and total cost recovery becomes larger. To the extent that the plants might not be able to recover the rest of the cost from capacity payments, our modelling results demonstrate the growing importance of additional revenue stream as renewable uptake intensifies.

3.2. Assumptions

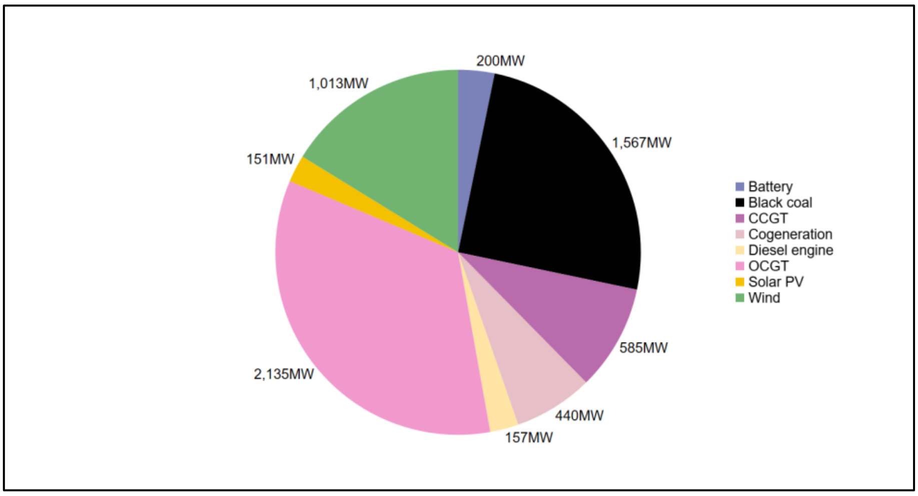
This section sets out the assumptions used in the modelling process.

3.2.1. Generator operating and cost paramaters

The operating and cost parameters of generating and storage units were obtained through the ERA's 2022 PLEXOS outputs and the 2020 Whole of System Plan (WOSP). Where data was unavailable through these sources, we inferred assumptions through the 2021 Integrated System Plan and other AEMO data sources, as well as our own analysis. Specifically:

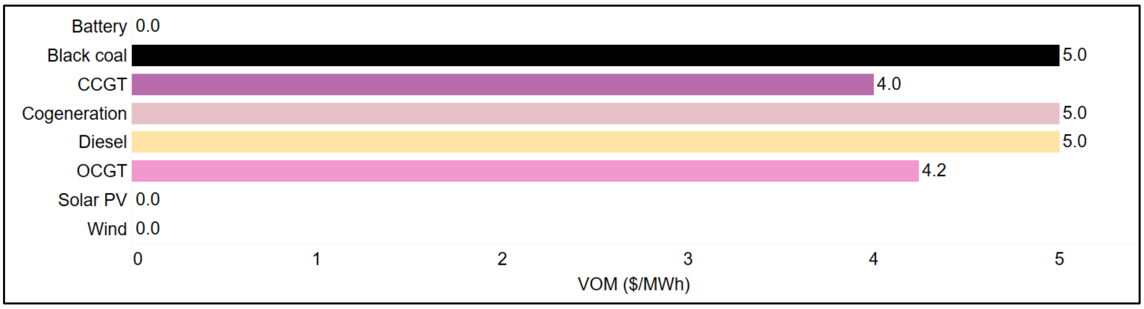
- **Existing capacity (MW)** from the ERA's 2022 PLEXOS model - Figure 3[17].

Figure 3 - Existing capacity (MW)



- **Auxiliary load (%)** from the 2020 WOSP
- **Thermal efficiency (%)** from the 2018-19 GHD report via AEMO
- **Fuel price ($/GJ)** from the ERA's 2022 PLEXOS model. We have assumed fixed fuel prices over the modelling horizon.
- **Variable operations and maintenance cost ($/MWh)** from the 2020 WOSP - Figure 4.

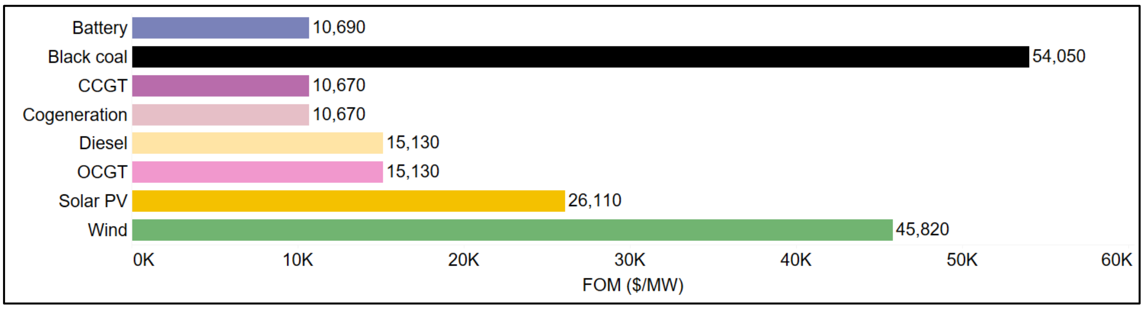
Figure 4 – VOM ($/MWh)



[17] To be clear, battery capacity was also derived from ERA's 2022 PLEXOS model.

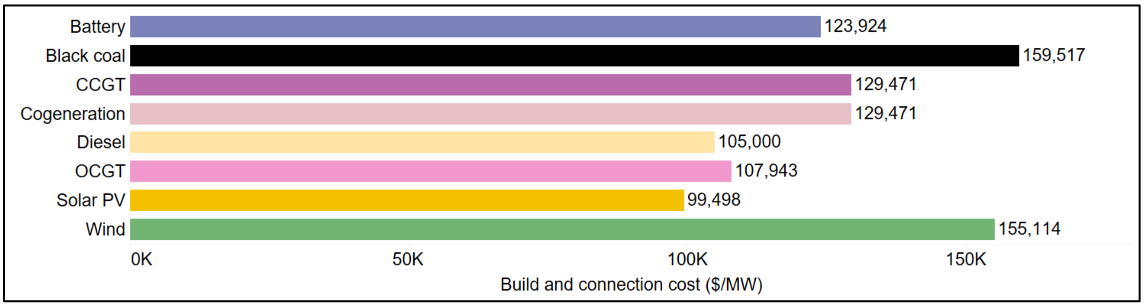
- **Fixed operations and maintenance cost ($/MW)** for batteries from the 2021 ISP and for other technologies from the 2020 WOSP - Figure 5.

Figure 5 - FOM ($/MW)



- **Build cost ($/MW)** from the 2020 WOSP assuming the 2022-23 'Techtopia' scenario - Figure 6.
- **Connection cost ($/MW)** as a ratio of build cost inferred from the 2021 ISP - Figure 6.

Figure 6 - Build and connection cost ($/MW)



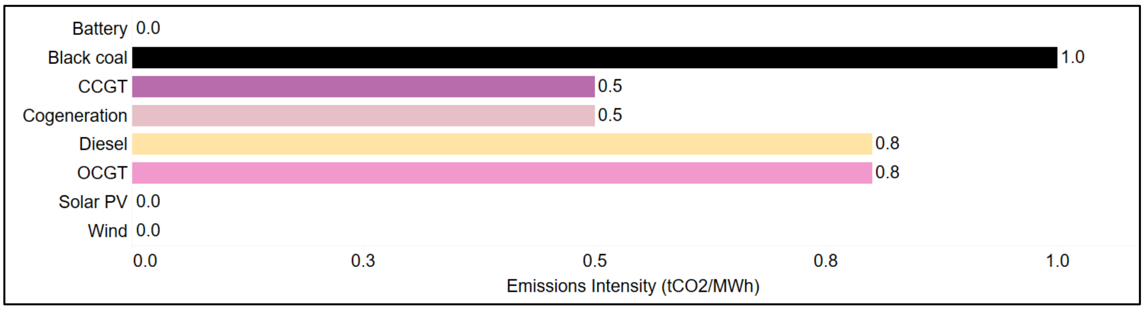
- **Existing storage capacity** (MWh) from the ERA's 2022 PLEXOS model.
- **Round trip efficiency** (%) by averaging charge and discharge efficiency from the ERA's 2022 PLEXOS model.
- **Annual cycles**, assuming 365 per year.

3.2.2. Other assumptions

Emissions Intensity Parameters

Data for Emissions Intensity (tCO2/MWh) was not available through the WOSP or through the ERA's 2022 PLEXOS model. We have therefore used assumptions developed from our own independent research for these values – Figure 7.

Figure 7 - Emissions Intensity (tCO2/MWh)



Traces

Data for demand and VRE traces (MW) were sourced through the ERA's 2022 PLEXOS. To be clear, these figures show the average time of day traces for demand and VRE respectively.

3.3. Results

This section sets out the results of our modelling.

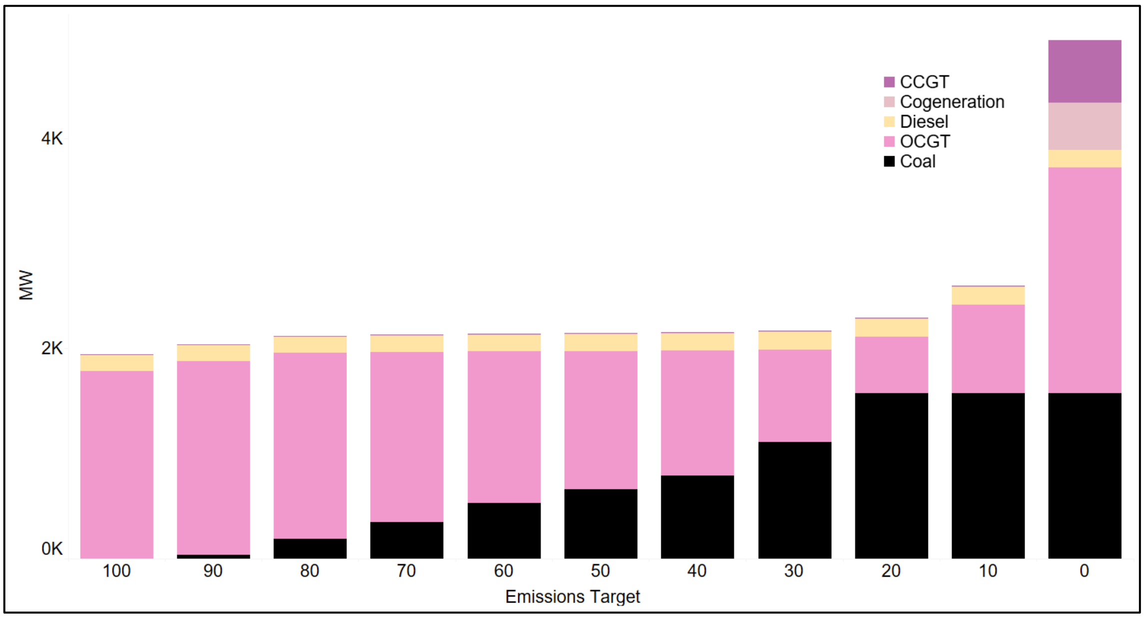
3.3.1. Generation mix

The following charts show the modelled retirement and entry decisions for ten different emission targets ranging from net zero emissions (shown on the left-hand side of the charts) to a world where no constraints are imposed on the level of emissions (referred to as the 'baseline scenario' on the right-hand side of the charts. Emissions targets between these two extremes vary by 10% increments.

To be clear, an emissions target of 50% can be interpreted as 'emissions cannot exceed 50% of the total emissions produced under the baseline scenario'.

Figure 8 shows the modelled retirement by technology at each emissions target.

Figure 8 - Modelled retirement for each emissions target

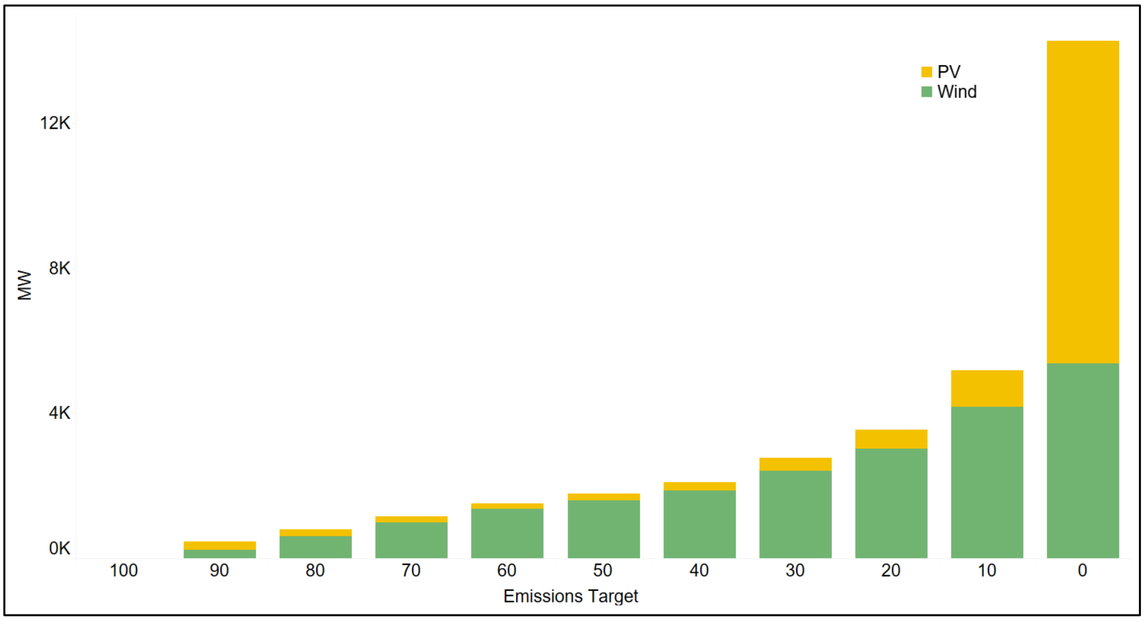


The chart indicates that as the emissions target tightens (i.e., approaches net zero emissions), thermal generators tend to retire. Retirement decisions are driven by the objective to minimise costs and the carbon constraints imposed at each emissions target.

OCGT (pink) and diesel (light yellow) retire early due to their SRMC (driven by fuel price, VOM, heat rates and emission intensities), followed by coal (black) and lastly CCGT (purple) and cogeneration (light pink). The latter two, here, generally have the lowest costs and emission intensities out of all thermal generators and so are only driven to retire once the emissions target reaches net zero.

Figure 9 shows the modelled entry for VRE technologies at each emissions target.

Figure 9 - Modelled entry of VRE for each emissions target



VRE incrementally enters as the emissions target tightens (i.e., approaches net zero emissions). Other than at net zero, more wind (green) typically enters than solar (yellow). This is because the wind trace is more favourable than the solar trace, i.e., it has a much higher and a more stable capacity factor than solar.

Figure 10 shows the modelled entry for batteries at each emissions target.

Figure 10 - Modelled entry of battery capacity (MW) for each emissions target

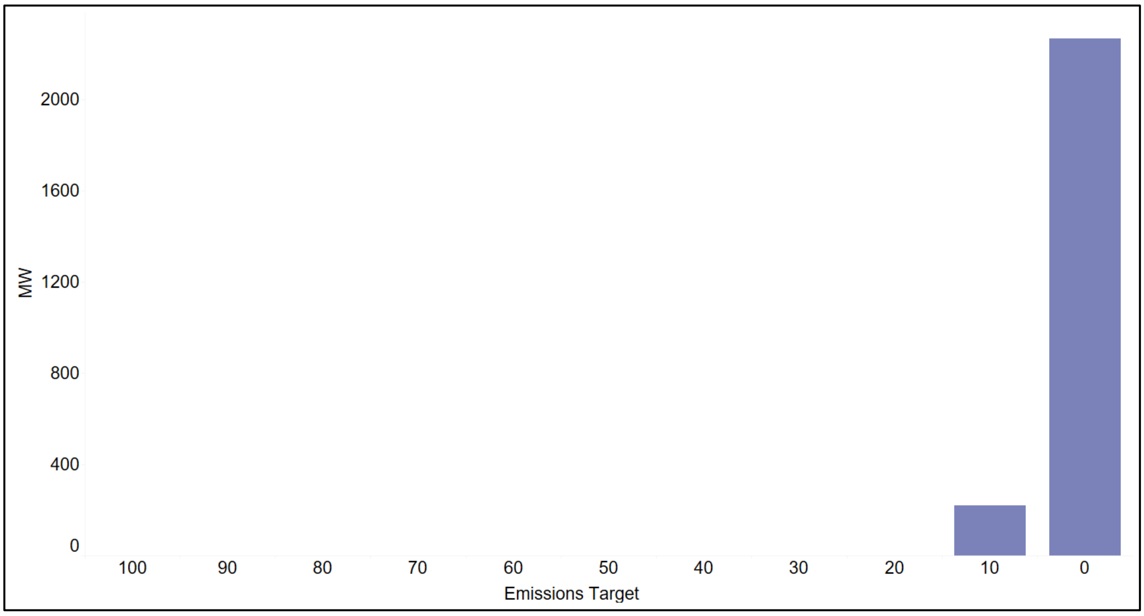
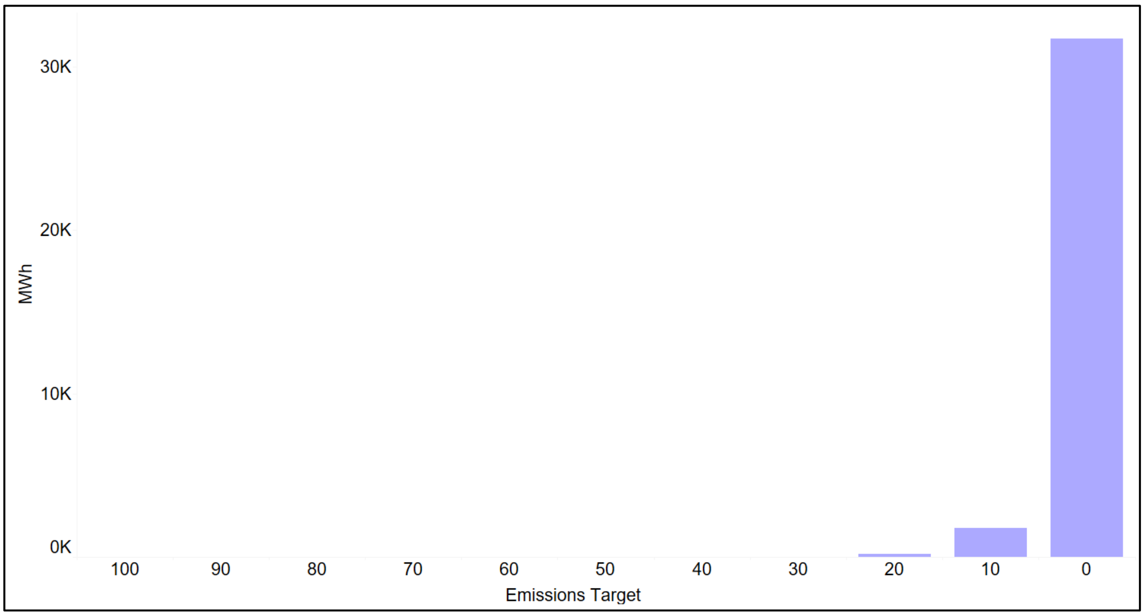


Figure 11 - Modelled entry of energy storage (MWh) for each emissions target



While VRE enters incrementally at each emissions target (Figure 9), batteries only start to enter at an emissions target of around 20%, and only substantially at 10% of net zero emissions. To be clear, Figure 10 refers to battery capacity as measured in MW (i.e., the maximum amount of power that a battery can instantaneously produce on a continuing basis) while Figure 11 refers to energy storage as measured in MWh (i.e., the amount of energy that can be discharged before the battery must be charged).

3.3.2. Energy prices

Figure 12 - Modelled average prices with and without a carbon price

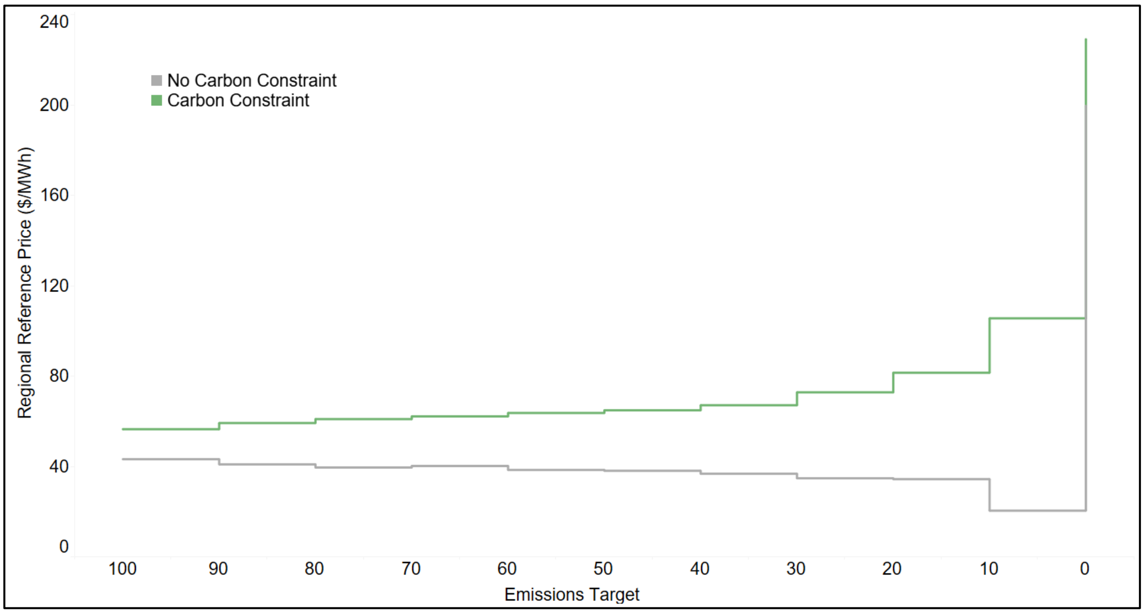


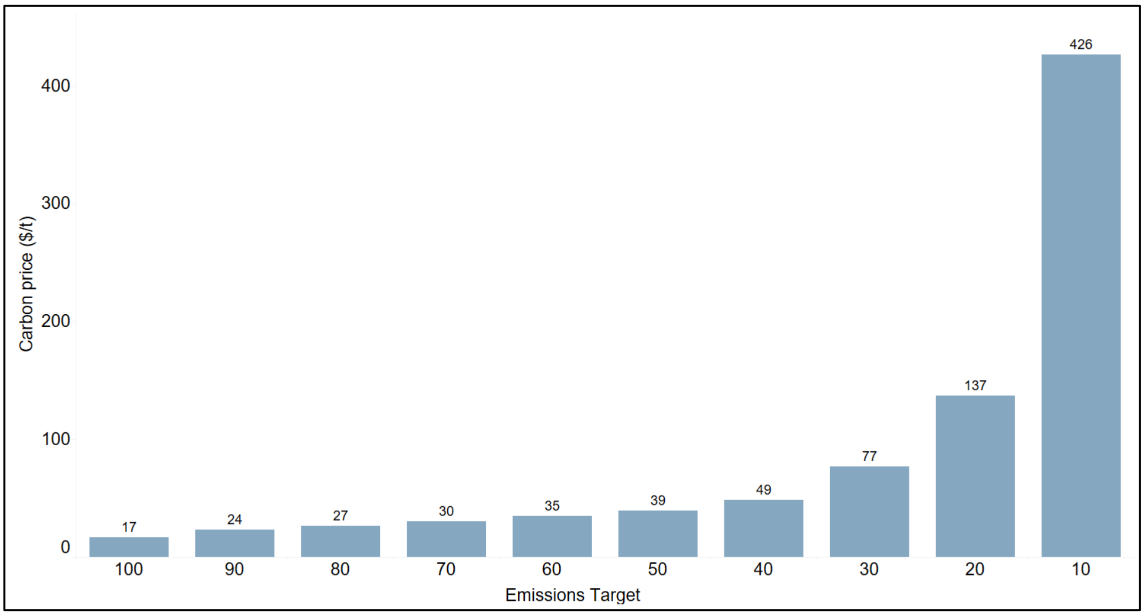
Figure 12 shows the modelled energy, SRMC based dispatch price outcomes at each emissions target. The green line is the price when we explicitly priced carbon (derived from the shadow price, or the marginal cost of meeting the emissions constraint). The grey line is the price where carbon was not explicitly priced. There are a few things we can infer from this chart.

The first is that as the emission target tightens (i.e., approaches net zero emissions), the energy price without a carbon constraint (i.e., grey line) falls; at the baseline scenario, the price is approximately $45/MWh but by an emissions target of 10%, the price has fallen to $20/MWh. Why does this occur? Generally, the increasing penetration of VRE invariably leads to a world where two different sets of prices exist: one where prices are set by VRE to their $0/MWh SRMC and the other where prices are driven by scarcity events to the value of lost load. For clarity, we emphasise that we have not modelled a constant market price cap as the market price cap can be expected to change over time depending on the marginal cost of different technologies.

The chart also shows that an implicit carbon price leads to a significant uplift in the overall price. We can see this as the green line (reflecting the marginal cost or shadow price of meeting the emissions constraint) is much higher than the grey line (reflecting the energy balancing constraints). Accordingly, the gap between the green line and the grey line is indicative of the effective carbon price at each emissions target - see Figure 13 below.

Lastly, the chart shows a significant step-up in prices going from a 10% to a net zero emissions target. This reflects the considerable level of unserved energy at net zero emissions shown in Figure 15 below.

Figure 13 – Modelled effective carbon price

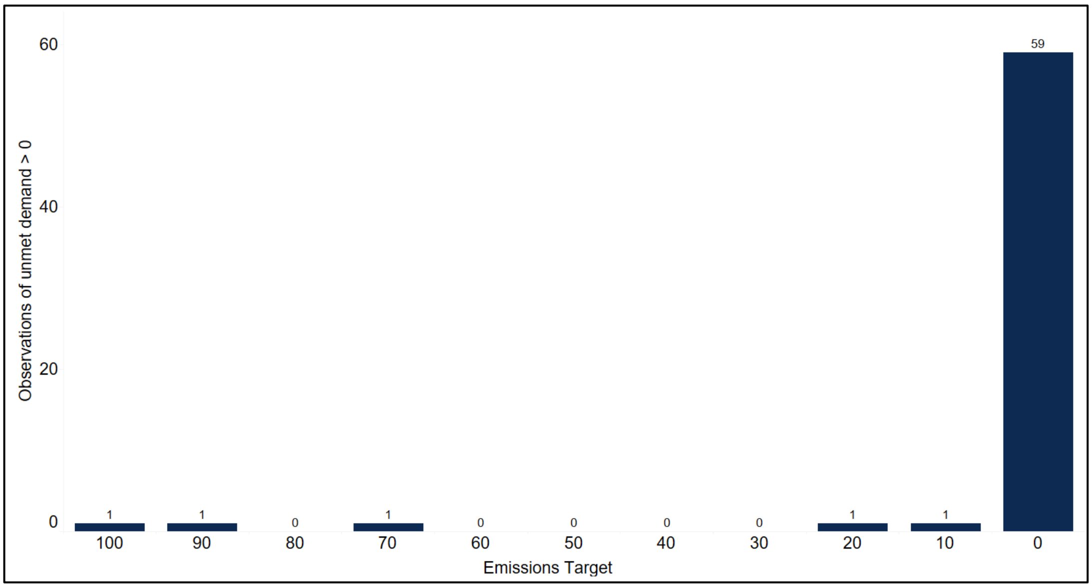


As mentioned above, Figure 13 shows the effective carbon price ($/t) inferred from the difference between the green and grey line in Figure 12. The chart highlights that the modelled carbon price is quite large from an emissions target of 30% onwards, reaching 426 $/t at an emissions target of 10%. We have not shown the carbon price at 0% emission as mathematically the shadow price of the emissions constraint becomes not well-defined when the emissions budget is exactly 0 ton.

3.3.3. Unmet demand

Figure 14 shows the number of observations where there was positive unmet demand (i.e., demand exceeded supply) over the one-year modelling horizon by emissions target. We note, this assumes perfect foresight of demand.

Figure 14 – Number of observations where unmet demand > 0



Unmet demand is minimal for the majority of emission targets (i.e., 10-100%) because there is sufficient fast response and dispatchable technologies (i.e., gas and coal) within the generation mix at these targets to meet demand.

At net zero emissions, there were 59 observations of unmet demand over the modelling horizon. This primarily occurs due to the variable, intermittent nature of wind and solar, which restricts the ability of supply to meet demand.

The magnitude of unmet demand events at net zero emissions is shown in Figure 15.

Figure 15 – Histogram of unmet demand (MW) at net zero emissions

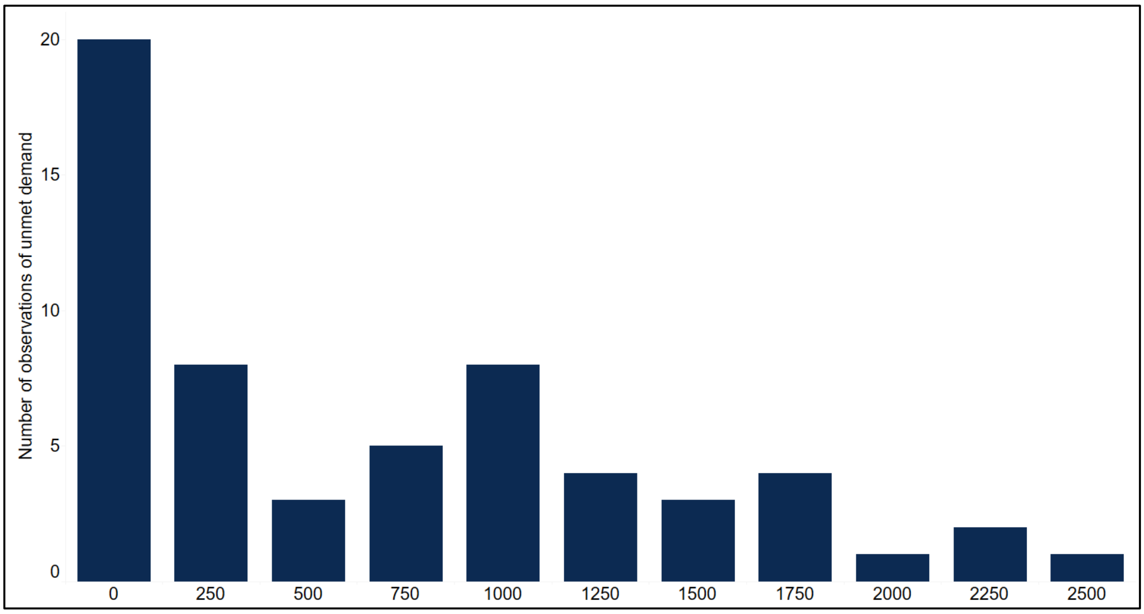


Figure 15 shows the number of observations of positive unmet demand over the modelling horizon at net zero emissions across 250 MW incremental bins.

The chart indicates that the majority of observations (around 20 observations) of positive unmet demand mainly sit within a range of 0 to 250 MW. The number of observations of positive unmet demand then reduces at the size of the unmet demand observed decreases – that is, there are very few cases of positive unmet demand greater than 1000 MW and even fewer that are greater than 2,000 MW.

3.3.4. Revenue sufficiency

The following charts show revenue sufficiency for facilities at each emission target and by technology. To reiterate, revenue sufficiency here only relates to the energy market – we have not included analysis of the capacity market side.

To be clear, revenue sufficiency is defined by the extent to which a facility can recover its costs. In the following charts, a facility's revenues are sufficient if the bars (indicative of revenue less variable costs) are at least as high as the red horizontal line (representative of the facility's total annualised build, connection and FOM costs).

Variable renewable energy

Cost recovery for renewables is determined by the extent to which the prices received sit above their marginal costs. As shown in Figure 12 above, prices are generally higher once a carbon constraint is included in the model.

Accordingly, VRE facilities (wind in Figure 16 and solar in Figure 17) recover their costs when carbon is explicitly priced, i.e., the green (for wind) and yellow (for solar) bars meet the red horizontal line.

In contrast, in the absence of a carbon price, VRE facilities do not recover their costs. Here, the degree of revenue insufficiency also grows as the emissions target tightens. Again, this is reflected in the lower prices when a carbon constraint is not included in the model (Figure 12).

Figure 16 – Revenue sufficiency for wind farms

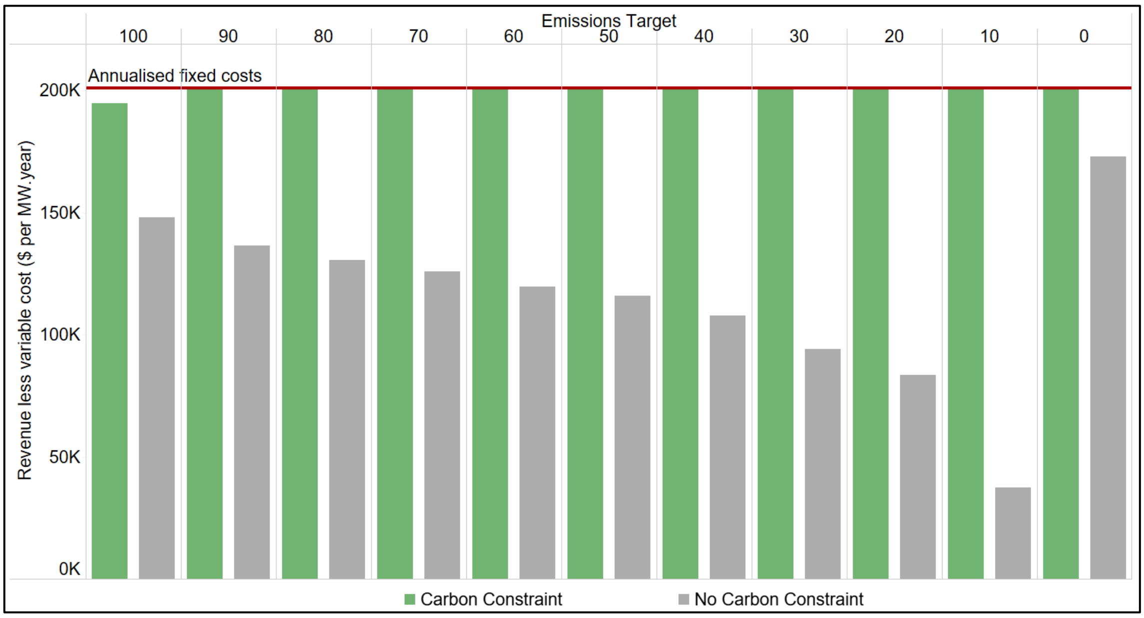
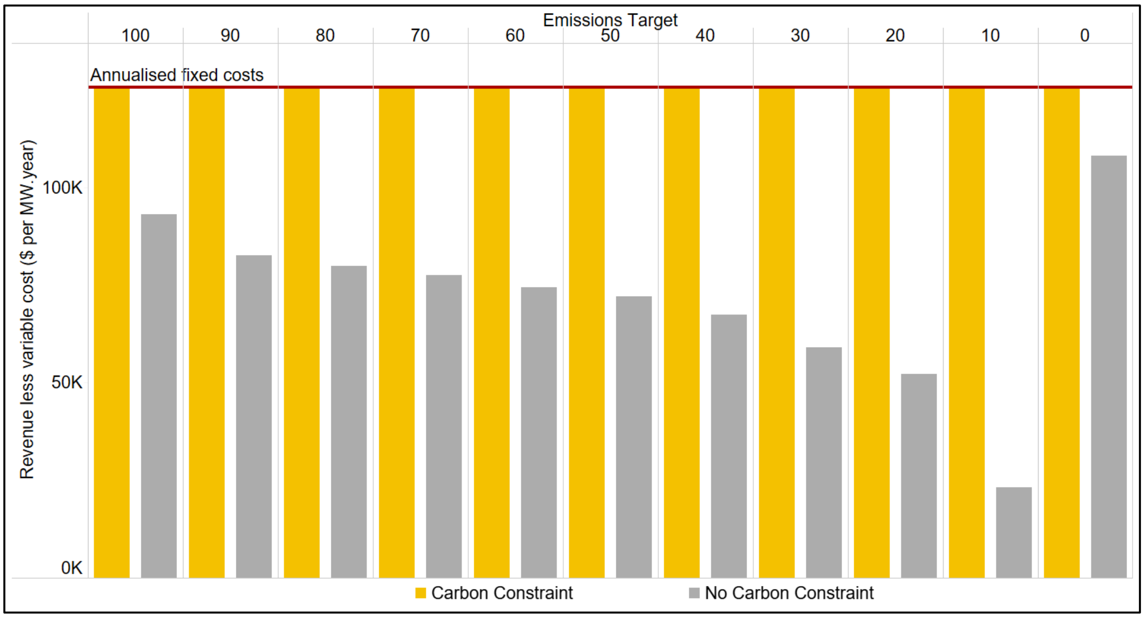


Figure 17 – Revenue sufficiency for solar farms



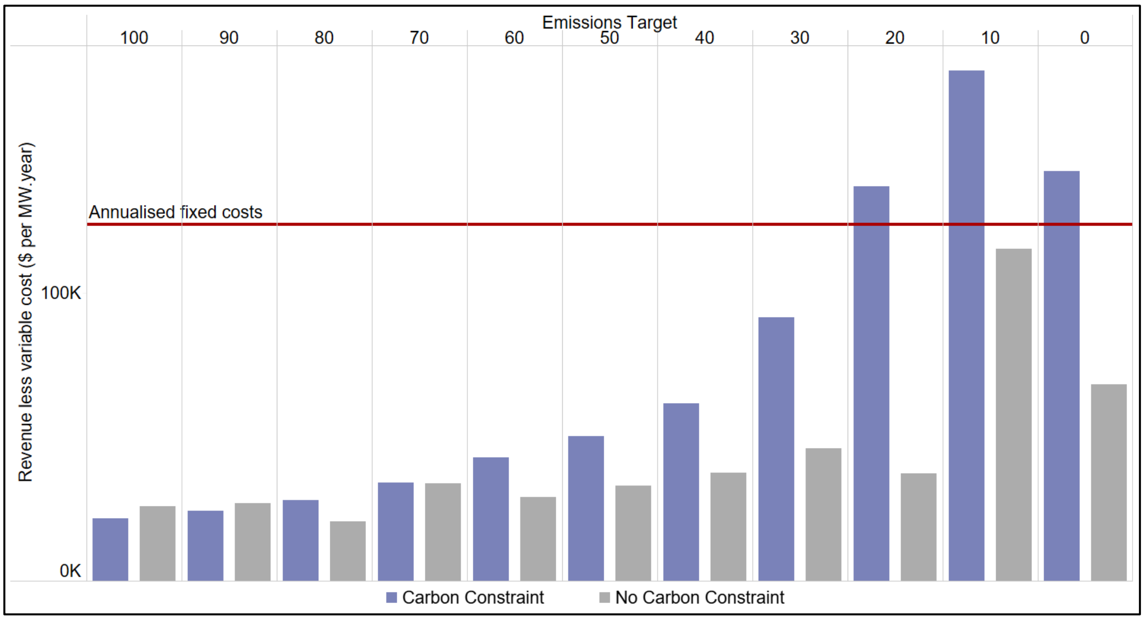
Note that if we include allowances for capacity payments under the RLM $35,600/(MW.year) for wind and $23,700/(MW.year) for solar, there is still a shortfall in revenue. This suggests that some additional value stream would be required to deliver the build profile that satisfies the carbon constraint.

Batteries

Where revenue for VRE is mostly determined by the prices they receive and their availability, revenue for batteries is additionally contingent on charge and discharge decisions (when and how much). That is, unlike VRE, batteries are dispatchable units and have the option to arbitrage based on their expectation of the market price; they can store energy obtained when price expectations are low and inject stored energy back into the grid when price expectations are high. However, as battery must first charge (and pay the pool prices when doing so) before they can sell stored energy back into the market, they require sufficient price spread (instead of just high price levels) in order to make enough profit to recover their cost.

Figure 18 shows that battery revenues are sufficient from an emissions target of 0-20% with a carbon constraint, as well as from an emissions target of 0% without a carbon constraint. In these cases, there is sufficient price spread, in terms of size and frequency, for batteries to recover their costs. In all other cases (30-100% emissions target without a carbon constraint or 10-100% emissions target with a carbon constraint), batteries are unable to recover their cost due to the lack of energy price spread alone[18]. However, as we have indicated, the bulk of revenue at lower penetrations will be earned through the ESS. It therefore stands to reason that the profile of new build under a carbon constraint can be achieved even without an explicit carbon price.

Figure 18 – Revenue sufficiency for batteries



[18] In practice, we note battery could also receive revenue from ancillary service markets as well as capacity credit payments.

3.4. Key findings

Prices fall as the emission target tightens

The increasing penetration of VRE invariably leads to a world where two different sets of prices exist: one where prices are set by VRE to their SRMC and the other where prices are driven by scarcity events.. As modelled average prices tend to decrease incrementally at each emissions target, we can infer that the effect of low prices tends to dominate the effect of high prices driven by scarcity events (i.e., there are more observations of low-price events). It is this price effect that leads to the revenue cannibalisation of VRE.

Unmet demand increases as the emission target tightens

As the traditional thermal fleet (coal and gas) within the generation mix are displaced by VRE, there is an enhanced risk of not having enough dispatchable capacity to meet demand during low wind and solar output periods. In a 100% renewable world, it might not be cost effective to build enough VRE and storage capacity to ensure 100% reliability of supply.

A carbon price leads to a significant uplift in the overall price received by facilities

Greater VRE penetration (or lower emissions target) will lead to lower energy market revenue in for renewable plants. Our model estimates the marginal cost of meeting an emissions target via a carbon constraint. When carbon is priced, modelled energy prices reflect the marginal cost of meeting an emissions target in addition to the cost of balancing demand and supply. This establishes the “missing money” between energy market revenue and cost of meeting energy demand in a low emissions world (note we have not explicitly modelled the RCM here). In practice, this could be implemented via different policy mechanisms, such as a price for emission, a tradable emissions scheme or a direct subsidy to low emission technologies.
Battery revenue sufficiency is significant at low emission targets

Batteries charge and store energy when prices are expected to be low and inject stored energy back into the grid when price expectations are high. Subsequently, battery revenue is a function of this differential.

3.5. Recommended options

Our modelling shows that renewable plants generally do not recover their entire cost through energy market revenue. In addition, as more renewable capacity enters the market, the resulting revenue cannibalisation makes cost recovery from the energy market ever more challenging. While co-optimisation between energy and ancillary services will likely improve dispatch outcomes, this alone is unlikely to address the revenue adequacy issues for renewables given the scale of identified shortfalls. Storage plants, on the other hand, earn energy market revenue through price arbitrage and hence requires large price spread to recover their costs. In high VRE (low emissions) market settings, the intermittency of VRE output will lead to greater price spread, with storage plants able to earn sufficient energy market revenue.

There are three options available to address the revenue adequacy challenge in the WEM:

- **Increasing the energy market price cap:** Raising the MPC is unlikely to address the revenue adequacy challenge. High price events occur during periods of energy scarcity that are correlated with low renewable generation. VRE units are therefore unable to capture much of the value of a higher MPC.

- **Adjusting capacity payments:** The capacity payment to a participant is predominantly a function of the Reserve Capacity Price and the capacity credit received by the participant. The capacity credit, in turn, is determined by the technology specific derating methodologies for the plant. We note a review of the RCM itself is not within the scope of this study and will assume the current capacity market rules and process remain in place for the rest of this discussion. In the future, should batteries become the new marginal entrants that set the Benchmark Reserve Capacity Price (BRCP), their capacity payment could be directly linked to their fixed cost. As a result, there could be greater certainties for batteries to recover their cost through a combination of energy and capacity market payments. VRE generators, on the other hand, are unlikely to be the marginal plant setting the BRCP, and their capacity payments might continue to be delinked from their fixed cost. As a result, there is no guarantee that, as energy market revenue decreases for VRE plants, their capacity payment will increase to provide sufficient overall revenue.
- **Additional revenue streams for the "missing carbon market":** Our modelling has demonstrated that VRE entrants will generally be able to recover their costs when the cost for emissions abatement is explicitly priced. This suggests that the revenue sufficiency problem for VRE plants fundamentally arises due to the missing carbon market. This is intuitive considering one MWh produced by a VRE plant and a thermal plant is equivalent only in terms of meeting demand, but the drive for zero-emission means renewable energy has some intrinsic social value that is external to the energy market. In the absence of any explicit carbon policy, energy and capacity prices themselves will not capture the value of emissions abatement and consequently will not provide sufficient price signals to attract the required VRE capacity for the net-zero target. While we modelled carbon revenue through a generic carbon constraint, in practice this could be implemented via different policy instruments including pricing emission, establishing tradable emission schemes, or direct, targeted subsidies to renewable plants coupled with coordinated exit of the existing thermal fleets.

In summary there are only three levers available to deal with revenue adequacy in the WEM, one of which (raising the MPC) is unlikely to work, and the other (adjusting capacity payments) is poorly suited to the task. The final option is to introduce additional revenue streams that reflect the value of the "missing carbon component".

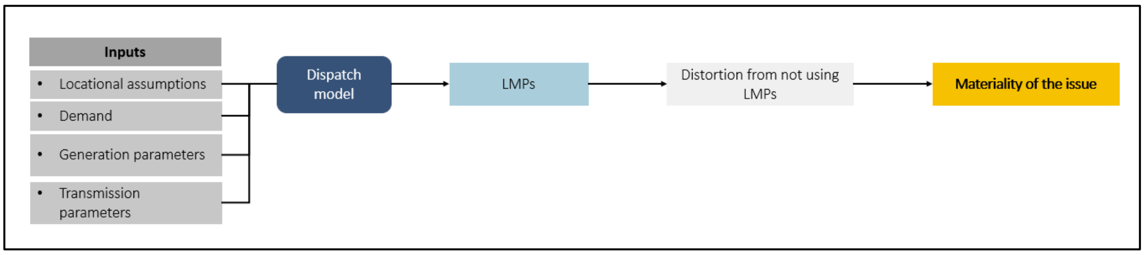
4. Nodal model

This section describes the methodology, assumptions and findings from our nodal model. In particular, the model allows us to demonstrate the materiality (i.e., significance, timing, conditions, recommendations) of locational marginal pricing as an efficient locational price signal in leading to optimal decision-making for generation investment.

4.1. Methodology

We built a nodal model of the WEM to assess the impact of LMPs in leading to more efficient price signals for generation investment – see Figure 19.

Figure 19 – Overarching methodology for nodal model



The model itself was built in PLEXOS using the linearised DC Optimal Power Flow setting. The model determines least-cost dispatch and real power flow quantities at each modelled node subject to specified technological and transactional constraints, such as thermal limits on transmission lines.

4.2. Assumptions

This section sets out the assumptions used in the modelling process.

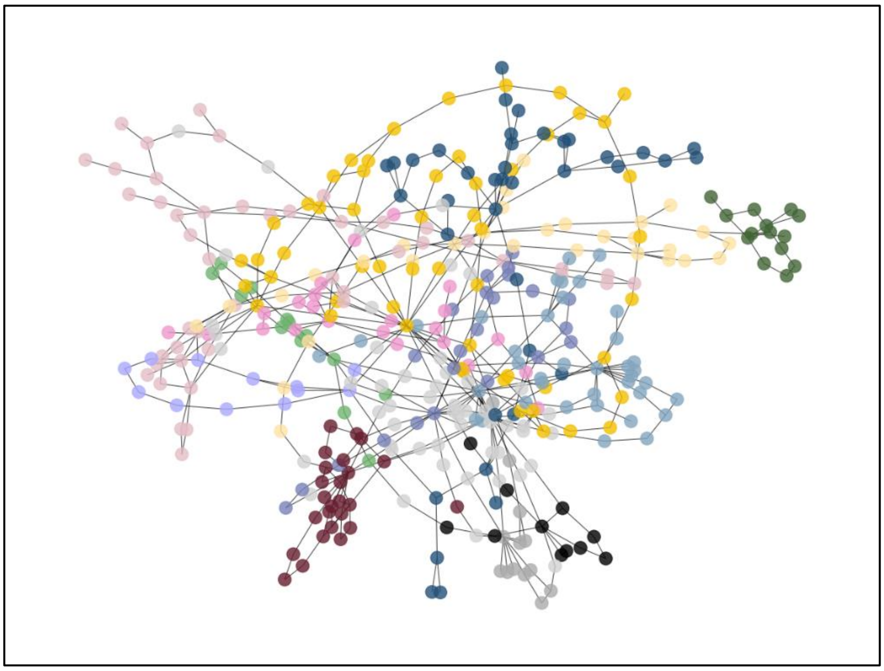
4.2.1. Locational assumptions

Locational assumptions used in the model were sourced from the PSSE provided by the ERA. Specifically, our model considered:

- 14 zones or 'regions'.
- 395 nodes spread across the zones, 110 of which have access to rooftop PV.
- 347 transmission lines connecting the nodes.
- Electric buses for each node allowing electricity to flow freely within the node.

Using data provided by the ERA, we then mapped all of this (i.e., buses to nodes; nodes to zones; lines to nodes) together to form the nodal representation of the WEM below shown in Figure 20. The circles reflect different nodal points and the branches represent transmission lines. The different colours are indicative of the fourteen different zones.

Figure 20 – Indicative nodal representation of the WEM



Our model assumes that nodes are load and / or generation points. That is, depending on the node:

- Generators can submit their bids; or
- Demand can be priced and cleared; or
- Both, i.e., generators can submit their bids and demand can be priced and cleared.

The 'type' of node (i.e., generation and / or load point) for each node was identified in the mapping process described above.

4.2.2. Other assumptions

Transmission

Data for transmission was derived from the BRANCHES data provided by the ERA in the Power System Simulator for Engineering (PSSE) files. There were three main line properties used:

- R – Resistance, used in determining line losses.
- X – Reactance, used in creating Y-Bus admittance matrix,
- RATE1 – Rating in MVA. A power factor of 0.95 was applied to the rating to convert it to MW used in PLEXOS. The reverse flow was included as the negative for the RATE1.

'Missing' transmission lines as a result of aggregation processes (i.e., aggregating buses to a node) were assumed to be unconstrained.

Generation

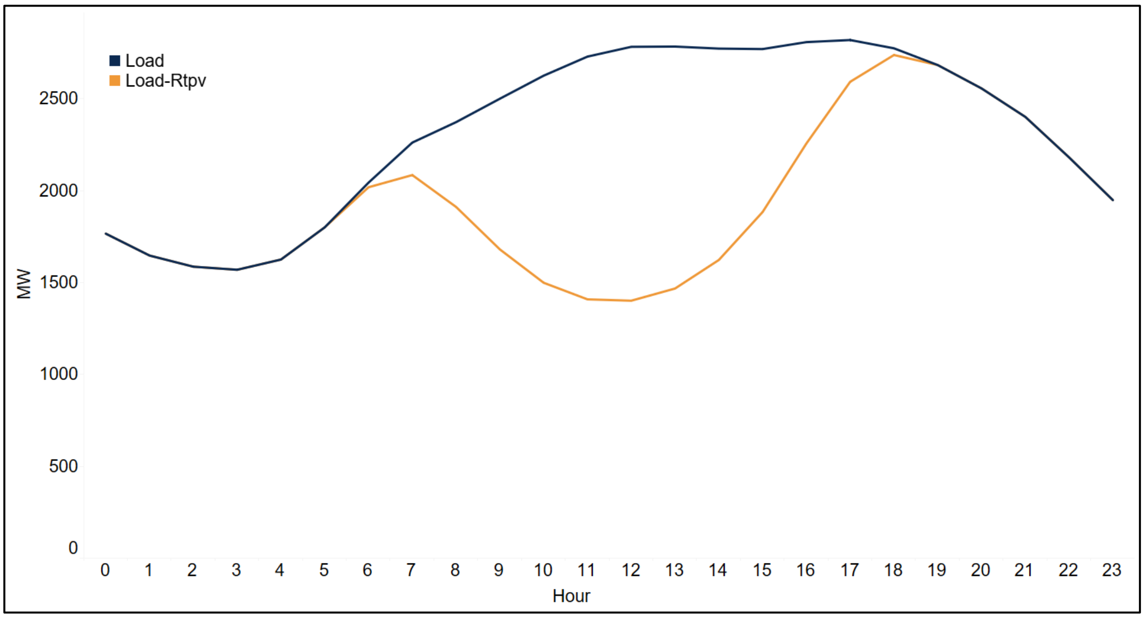
Generator properties were derived from the ERA's existing zonal PLEXOS model. This included both operating and cost parameters.

System demand

Demand inputs were provided from ERA's existing zonal PLEXOS model and were mapped to nodes through load participation factors (LPF). The LPF was based on the proportion of active power to total sum of system, which was sourced through the LOAD data provided in the PSSE files.

Rooftop PV generation was also considered in the model. It was mapped proportionally to 110 of the nodes, added to the operating demand data provided by the ERA (see Figure 21 below) and used to update the LPFs.

Figure 21 – Average load over the year by time of day



4.3. Results

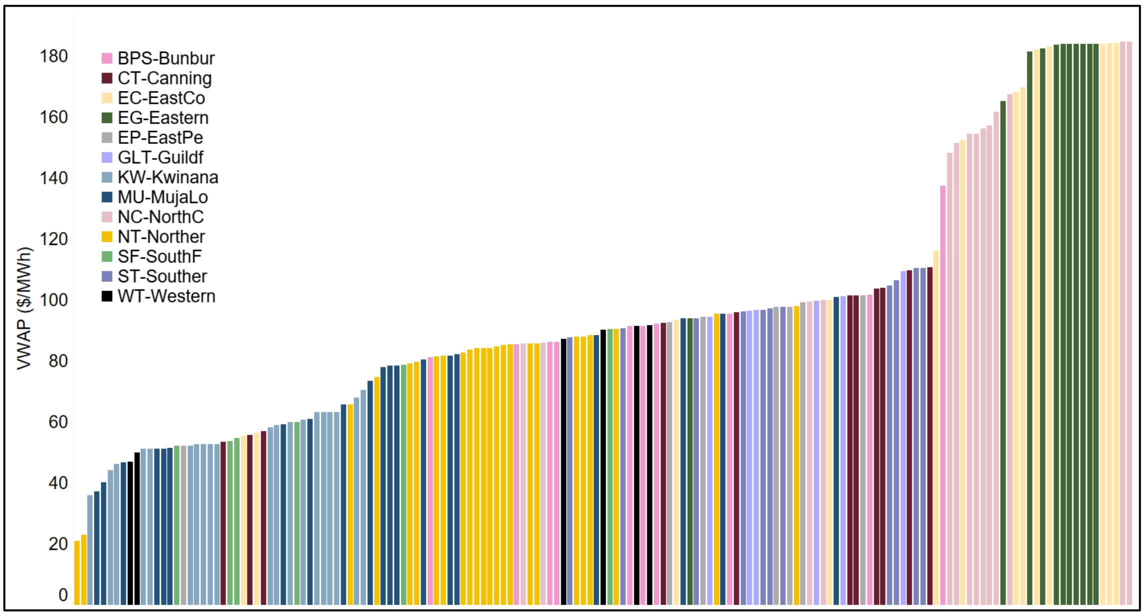
Figure 22 below shows the modelled volume weighted average price (VWAP) for various nodes in the WEM. Each bar corresponds to a different node while the colours are indicative of the 14 different zones. Nodes are therefore grouped by their zones and are ordered by modelled price outcomes.

The chart highlights substantial LMP separation across nodes. The lowest VWAP across all nodes is a node in the Northern zone at 21 $/MWh while the highest VWAP is a node in the NorthC zone at 184.8 $/MWh.

This price separation implies that LMP could function as an efficient price signal to support locational decisions because it informs generation facilities which nodes they should build at.

Despite this price separation, the chart also suggests that LMPs are positively correlated by zone. That is, the prices for nodes within a zone are usually within range of each other. We can see this, for example, as the prices for nodes in the NorthC, Eastern and EastCo zones all tend to be relatively high at 140+ $/MWh while prices for nodes in the MujaLo and Kwinana zones all tend to be relatively low at 40-60 $/MWh. Price similarity on a zonal level occurs because nodes within the same regions tend to be subjected to the same operational conditions.

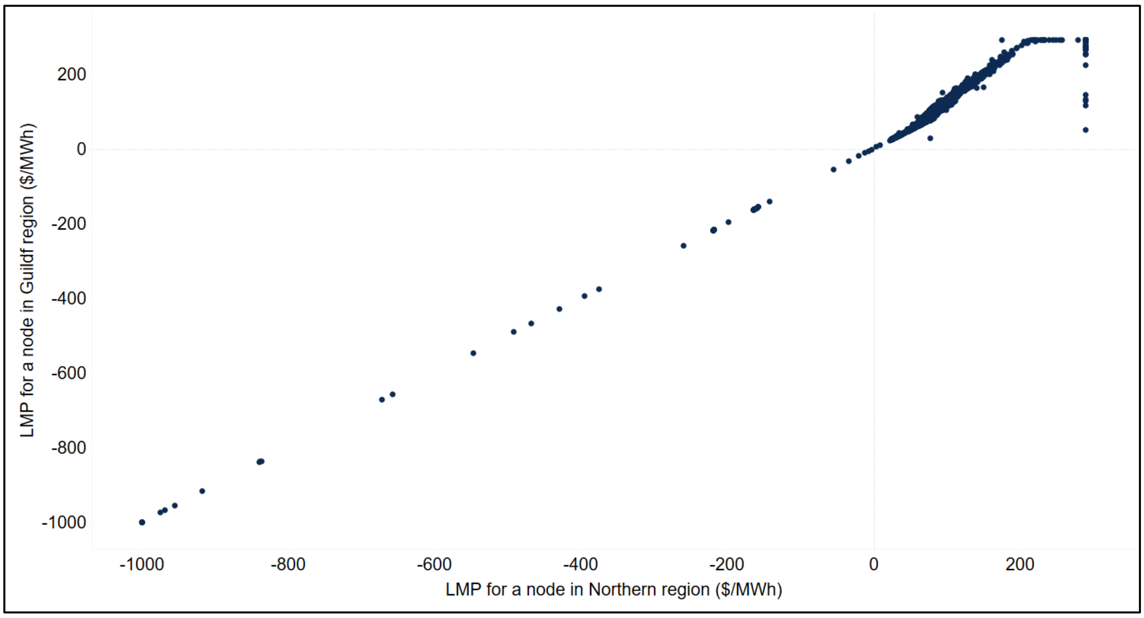
Figure 22 – Volume weighted average price by zone



There is more price spread when one of the prices in one of the locations exceeds $200/MWh.

Figure 23 below, which shows a strong linear relationship in prices for two nodes up to approximately $200/MWh – that is when prices are high in one node, they tend to also be high in the other. There is more price spread when one of the prices in one of the locations exceeds $200/MWh.

Figure 23 – Prices for nodes in the Northern and Guildf regions



Interestingly, these two nodes sit within different zones, suggesting that not only are prices positively correlated on a zonal level (as shown in Figure 22), they can also be positively correlated on a nodal level.

This correlation occurs due to the effect of rooftop solar PV, which reduces consumer reliance on the grid and in turn the degree to which consumers are subjected to and receive LMPs. Consistent with this, LMPs are highest and tend to diverge when the availability of rooftop solar PV is limited (see top right corner of the chart).

4.4. Key findings

Price separation between nodes is substantial

The difference between average VWAPs for the nodes with the highest and lowest VWAPs is 163.8 $/MWh – shown in Figure 22 above. This implies that locational marginal pricing could function as an efficient price signal to support locational decisions because it informs generation facilities which nodes they should build at.

LMPs generally move together but can diverge

Our analysis from Figure 22 and Figure 23 suggests nodes can be positively correlated on both a zonal and nodal level. The correlation on a zonal level occurs because nodes within the same regions tend to be subjected to the same operational conditions, while the correlation on a nodal level occurs due to the effect of rooftop solar PV. Consistent with this, prices tend to diverge when the availability of rooftop solar PV is limited.

4.5. Recommended options

Our modelling has found that there are material variations in energy market prices in the SWIS across different locations, suggesting that a single zonal price will likely be less efficient than a full LMP. Our model is, however, illustrative in nature as it only models a single year market outcome reflecting the current WEM conditions. While our model has shown material locational variation in energy prices, it does not provide a cost benefit analysis of, or any direct evidence for, introducing an LMP in the WEM. While a full cost benefit analysis of the LMP does not lie within the scope of this work, we would like to offer the following observations regarding why there is *not* a need to introduce an LMP in the WEM in the current market condition:

- LMP creates additional price volatilities in thinly meshed networks that are prone to congestions (such as the SWIS). This could reduce local wholesale competition in areas whose prices often separate from the rest of the network and introduce additional uncertainties for new entrants.
- The implementation of the LMP is often a large-scale reform which could involve major changes in various aspects of the market process, such as dispatch (including the underlying dispatch engine), pricing and settlement. Additional financial instruments might also be needed to help participants mitigate locational price risks. Given the scale of the reform and the associated cost, one must be satisfied that the LMP would bring sufficient additional benefit considering other options available.
- In practice, the WEM already has, or will soon introduce other mechanisms for managing congestions in the form of SCED and the NAQ framework. At the operational timeframe, SCED would appropriately constrain generation and storage facilities based on real-time

congestion information. This would result in resources being exposed to the effect of congestion due to reduced output and forgone energy market revenue. The NAQ works as a rationing mechanism at the investment timeframe to ensure that resources are disincentivised to locate in congested parts of the network.

- Some markets such as the NEM coordinates the uptake of VRE through renewable energy zones (REZs), which are geographical locations with good wind and solar resources. In the NEM, the identification of REZs and the associated network investment are undertaken through the Integrated System Plan (ISP). The Whole of System Plan (WOSP) in the WEM could potentially perform similar functions in identifying priority network development projects. In other words, targeted system-wide planning, supported by rigorous engineering and market studies, could offer a viable alternative to pure price signals as a mechanism to coordinate generation investment.

We do not recommend the LMP in the WEM at this stage. The sweeping changes required by the LMP reform could significantly increase uncertainties and risks to new entrants, given the urgency of the renewable transition and the scale of the new renewable capacity needed in the coming years. This could create further barriers for new renewable investments. There are also alternative planning and policy mechanisms that could adequately manage congestions at both investment and operational timeframes.

We recommend that the ERA should continue to monitor the development of generation investment and resultant impact on network congestion in the SWIS in the coming years. The ERA should consider additional congestion management mechanisms – including the LMP – only if there is clear evidence that their benefit is likely to outweigh the implementation cost.

5. The NAQ Framework

This section discusses the materiality of the NAQ framework as a barrier to efficient locational outcomes.

Our assessment comprises:

- A brief outline of the nature and context of the NAQ framework;
- Examples of outcomes delivered by the NAQ framework under various scenarios; and
- Our evaluation.

5.1. Nature and context of the NAQ framework

Below, we set out our understanding of the NAQ framework to ensure clarity of the subject matter prior to discussing our evaluation of its materiality.

Background

Under the incoming constrained network access model in the WEM, facilities do not have inherent or guaranteed level of access in the network. Incumbent facilities face the risk of being displaced by new entrant facilities connecting to constrained parts of the network.

The NAQ framework is being implemented to prevent this.

What is the NAQ framework?

The NAQ framework allocates preferential capacity rights (i.e., credits) to incumbent facilities that dictate the quantity of energy they can inject into the system when the network is constrained. It has no role in the dispatch or settlement of energy or essential system service markets.

The assignment of a NAQ is a function of the facility's Certified Reserve Capacity and the network capacity. The equations are a simple representation of these functions:

$$NAQ \leq Certified\ Reserve\ Capacity$$

And

$$\sum NAQ = Network\ Capacity$$

It is our understanding that the NAQ allocation process also follows the same prioritisation process for accepting offers from capacity resources as the Reserve Capacity Mechanism (RCM). This becomes important below.

Key rules

The NAQ allocation process is governed by a set of key rules. We briefly outline these below:

- **Scheduled, intermittent and storage facilities can all participate to be allocated NAQs and in turn capacity credits.** For all these facilities capacity credits are assigned up to their capacity and capped by their allocated NAQ. They differ, however, by the way in which they are de-rated. Scheduled facilities are de-rated based on either historical or probable outage rates, as well as their expected performance at a temperature of 41°C.

Intermittent facilities are de-rated using the Relevant Level Methodology (RLM) and storage facilities are de-rated using a linear de-rated model, which accounts for the energy and time limited nature of the resources (i.e., how much energy they can contribute over eight trading intervals). It is our understanding that these methods are currently being reviewed by Energy Policy WA (EPWA) as part of the review of the RCM.

- **Once a facility has been assigned its NAQ, it retains its capacity right into perpetuity.** The exceptions to this are retirement or if a facility's Certified Reserve Capacity is reduced due to exogenous factors, such as changes to network capacity or demand. A reduction in VRE capacity through the RLM is also considered an exogenous factor here.
- **If a facility's capacity is reduced due to exogenous factors, that facility will be prioritised in the next cycle.** For example, if a facility loses its NAQ due to changes in the network capacity, it will have priority if things change back in their favour.
- **Facilities cannot transfer or trade credits to other facilities.** As we understand it, mechanisms to facilitate trading are being considered for the future.
- **There is an order of priority status in the NAQ assignment process.** In reality, the order is quite complex but can be simplified to the following:

  - Existing facilities
  - Facilities who were negatively impacted by exogenous factors in previous cycles
  - Network augmentation funding facilities
  - New committed floating price facilities
  - New committed fixed price facilities
  - New proposed floating price facilities
  - New proposed fixed price facilities

  Again, we note that in reality, the order is far more complex, and the above list is intended to capture the overarching nature of the priority status. For example, the order changes depending on whether there are offers from fixed price facilities and facilities that have applied for early CRC (and the treatment of these facilities differs depending on whether they are funding network augmentation).

5.2. NAQ framework outcomes

Below, we have provided a breakdown of possible outcomes delivered by the NAQ framework under different scenarios. While these examples are indicative and a simplified representation, they do show the invariable outcome delivered by the NAQ framework – that certain generators (specifically new entrants who are generally low-cost renewables) get 'crowded' or 'squeezed' out of the market.

Each of the charts below follow the same structure. The stacked bar chart on the left shows Certified Reserve Capacity within the system and the stacked bar chart on the right (which are in line with the rules and equations described above) are the allocated NAQs and capacity credits within the system. The different coloured bars are indicative of different types of facilities. The dotted red line is indicative of the total network capacity, which in this case has been set to 200 MW for the purpose of simplicity. Lastly, we note that each chart builds upon that which precedes it.

The key message of these charts is to show the marginal 'crowding out' of new facilities (which are likely to be low-cost renewables) as the residual network capacity incrementally declines.

Figure 24 - Existing facilities receive priority over new facilities

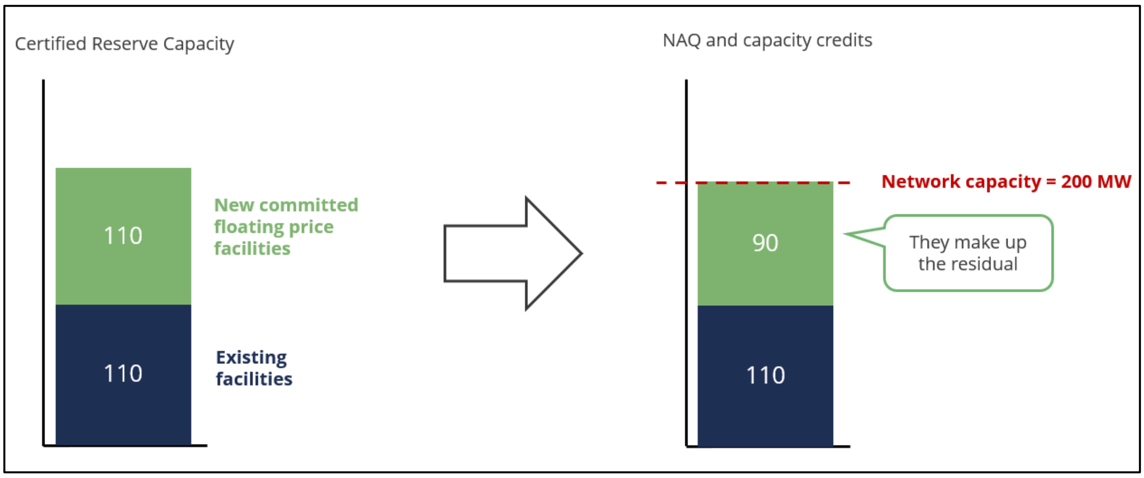


Figure 24 takes the example where existing facilities (dark blue) and new committed floating price facilities (green) both participate to receive capacity credits. The chart highlights that despite having 110 MW of Certified Reserve Capacity, new committed floating price facilities will only be assigned 90 MW worth of capacity credits. This occurs because existing facilities receive precedence and maintain their existing amount of capacity credits. That is, new committed floating price facilities are issued capacity credits equal to the residual network capacity, i.e., 200 MW minus 110 MW.

Figure 25 - Then facilities previously impacted by exogenous factors

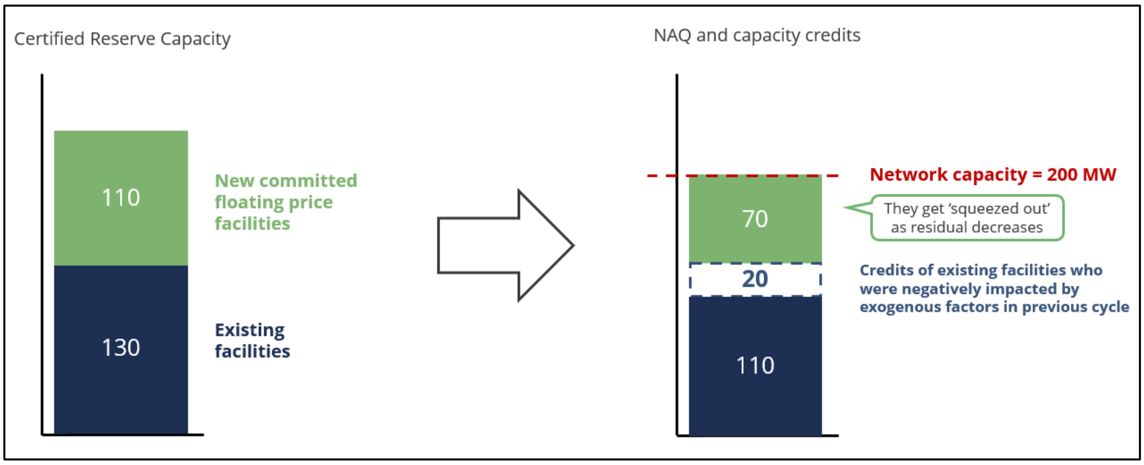


Figure 25 builds on Figure 24 to show that the residual network capacity and amount of capacity credits (i.e., 70 MW) assigned to new committed floating price facilities decreases once facilities who were negatively affected by external factors in previous cycles are included, i.e., new facilities get 'squeezed out'.

Figure 26 - Then facilities who have funded network augmentation

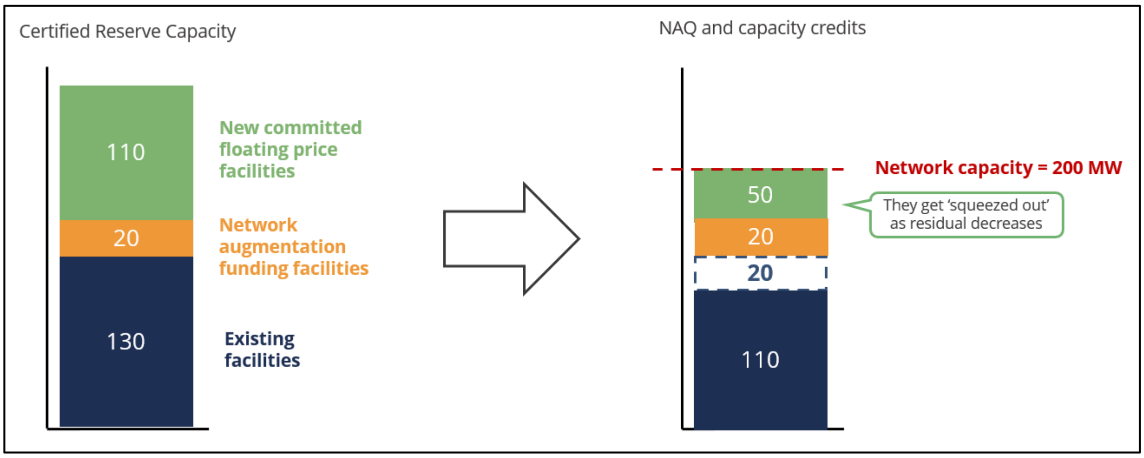


Figure 26 reinforces the same message as Figure 25 but this time new committed floating price facilities receive only 50 MW of capacity credits.

In the three charts above, it is also assumed that there is enough Certified Reserve Capacity in the market to meet the network capacity. If instead the network capacity were to have exceeded the aggregate Certified Reserve Capacity, then capacity would be procured by the remaining types of facilities shown in the order of priority in section 5.1.

5.3. Our evaluation

In light of these outcomes, it is clear that the NAQ creates a trade-off between competing inefficient outcomes.

One on hand, without the NAQ framework, incumbent facilities face the risk of being displaced by new entrants connecting to constrained parts of the network. This can lead to capital inefficiency and, in turn, deter investment. Displacement here may not generate a net improvement in the value of reliability, which could undermine the function of the RCM.

On the other hand, with the NAQ framework, low-cost new entrants are 'crowded out' from obtaining capacity credits until more network capacity becomes available. This can also deter investment and drive-up costs, undermining the underlying objective for the SWIS of minimal total system costs.

It would, however, be interesting to see what would happen if a mechanism was implemented to enable capacity credit transfer between facilities. If the profit of maintaining an older, high-cost facility exceeds the profit from trading capacity credits, then a mechanism could provide an incentive for these facilities to exit.

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Appendix 8 Report from consultant: FTI Consulting

AN FTI CONSULTING REPORT – PUBLISHED 20/07/2022

Battery Operation in the WEM

DRAFT REPORT FOR THE ECONOMIC REGULATION AUTHORITY (ERA)

EXPERTS WITH IMPACT™

Contents

Executive Summary

In recent years, several factors have created the need for changes to the design of the WEM. For example, increasing levels of intermittent renewable generation and rooftop solar are creating challenges for maintaining system security in real time. The WA Government's Energy Transformation Strategy **("the Strategy")** aims to address these challenges and ensure the continued reliability of the electricity system. Following the WEM reforms, battery storage systems will participate in both the balancing energy market and ESS real time markets **("RTM")** simultaneously and will seek to maximise revenue across these services.

FTI Consulting was engaged by the Economic Regulation Authority **("ERA")** to develop a model which simulates profit-maximising behaviour for battery storage facilities operating in the Wholesale Electricity Market **("WEM")**, after new market commencement. The purpose of this report is to provide a summary of results from modelling battery revenue within the WEM to support the ERA's market modelling that will inform their report to the Minister for Energy in October 2022. FTI have developed a Battery Revenue Optimisation Model **("B-ROM")** to simulate the dispatch of a grid-scale battery storage system under the new market rules for every 30-minute trading interval. B-ROM simulates battery operation by optimising across revenues achieved in the real-time energy market and compensation payments for remaining on standby in the Essential System Services **("ESS")** market.

A high-level summary of results is presented in the table below. The operating mode refers to which markets the battery storage system is participating in within B-ROM when optimising for revenue. For example, a battery in 'ESS only' mode will not participate in the energy market and will earn all of its revenue from ESS markets.

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Summary net revenue based on different operating modes in B-ROM

Operating Mode	Q4 2023	CY 2024	CY 2025	Q1-Q3 2026	Total
Energy arbitrage only	$1.26m	$2.92m	$1.71m	$0.70m	$6.59m
ESS only	$3.95m	$8.33m	$3.53m	$0.91m	$16.72m
Energy + ESS	$4.47m	$9.33m	$4.37m	$1.46m	$19.64m
Energy + ESS + capacity credit obligation (excl. capacity credit revenue)	$4.27m	$8.65m	$3.78m	$1.22m	$17.92m

Based on the modelling conducted to date, we have found that current price spreads in the WEM's balancing market result in low revenue for a battery participating in the energy market alone. ESS revenue is the dominant revenue stream for a battery storage system however, these profits can collapse substantially with increased saturation of battery projects increasing competition for ESS provision.

Introduction

Like most electricity systems around the world, the Wholesale Electricity Market **("WEM")** is experiencing unprecedented transformation driven by the rapid uptake of intermittent renewable generation and distributed energy resources. As part of this transformation, the Western Australian **("WA")** government's Whole of System Plan **("WoSP")** has signalled the importance of energy storage, such as batteries, to enable high levels of generation capacity in the WEM to be renewable by 2040.[1]

Despite the importance of storage, there are currently no battery storage systems operational in the WEM.[2] Combining the lack of current battery storage systems and ongoing changes to the WEM market rules, it is unclear how battery storage systems are likely to participate in the WEM. The purpose of this report is to provide a summary of results from modelling potential battery storage behaviour participating competitively within the WEM for the purposes of revenue maximisation to support the Economic Regulation Authority's **("ERA")** simulation of the WEM.[3] This report documents the methodology and results of the battery optimisation model developed by FTI Consulting to reflect profit maximising behaviour across a co-optimised energy and ESS market design in the ERA's market modelling.

Additionally, this work will inform the ERA's report to the Minister for Energy in October 2022 on assessing the extent to which the WEM is achieving its five market objectives:

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

The report is structured as follows:

- Section 3 covers the background and context of the WA government's Energy Transformation Strategy and how this is relevant for battery storage systems entering the WEM.
- Section 4 sets out the approach used by FTI Consulting to model the behaviour of battery storage systems in the WEM and their associated revenue.
- Section 5 outlines the preliminary findings and provides key insights about battery storage behaviour in the WEM.
- Section 6 summarises the key themes that surfaced during stakeholder consultation conducted by the ERA and FTI Consulting
- Section 7 provides a high-level overview of what implications the modelling results have for investment in battery storage in the WEM.

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[1] See page 10 and page 73, https://www.wa.gov.au/system/files/2020-11/Whole%20of%20System%20Plan_Report.pdf

[2] It should be noted that several market participants have signalled their intention to explore the deployment of battery storage in the WEM, including Synergy.

[3] The ERA's market modelling is conducted using Energy Exemplar's PLEXOS software.

Background and context

In recent years, several factors have created the need for changes to the design of the WEM. Increasing levels of intermittent renewable generation and rooftop solar are creating challenges for maintaining system security in real time.[4] The WA Government's Energy Transformation Strategy ("**the Strategy**") aims to address these challenges and ensure the continued reliability of the electricity system. Batteries will play a key role in the transformation of the WEM, and there are several key pillars of the Strategy that are relevant to battery storage:

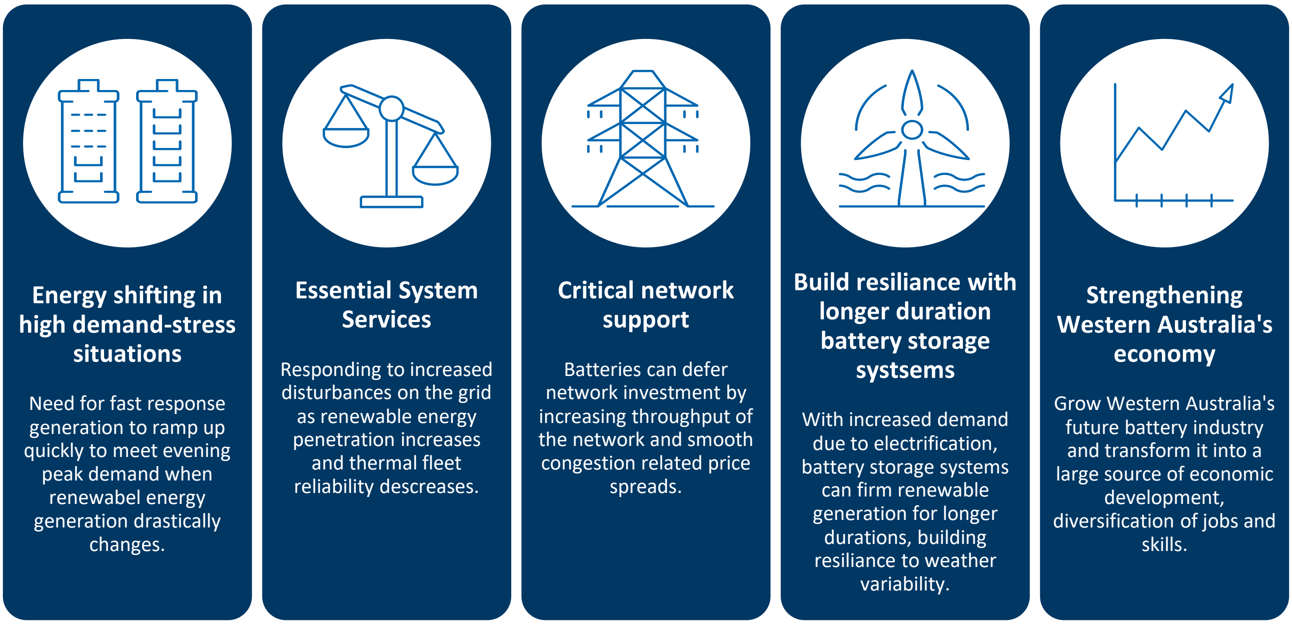
- **New design of Essential System Services (ESS) markets.** To support the Energy Transformation Strategy, the WA government via the Australian Energy Market Operator ("**AEMO**") is modernising the WEM to enhance system security and enable greater access to the network for new generators. The transition includes a shift to a Security-Constrained Economic Dispatch ("**SCED**") engine that will co-optimise energy and ESS services to achieve a low-cost solution for the benefit of consumers. As a result, ESS services will be procured through the new engine with prices set through a recurring competitive auction every 30 minutes.
- **Supporting higher levels of intermittent renewable generation penetration.** The latest AEMO forecast is that unconstrained minimum demand could fall to as low as negative 37MW within the next five years.[5] Battery storage can help support higher levels of low-cost intermittent generation – both grid connected and DER – before this needs to be constrained during minimum demand periods. Battery storage may provide a lower cost option for ESS during minimum demand periods compared with alternatives.
- **Integrating new technology including preparing the grid for increased electrification in time.** New technologies such as battery storage, electric vehicles, and distributed energy resources (**"DER**") are changing the way we think about electricity markets and changing what we demand from our electricity grid. No longer are our electricity systems a one-way transfer of energy from generator to customer but are increasingly a multi-directional system. Battery storage will play a key role in ensuring new technology can be integrated and the system is prepared for greatly increased demand in the future due to electrification. Given the substantial uptake of DER in the WEM, some key existing facilities including government owned thermal generators supplying ESS are expected to exit the market and there is a need for investment in replacement services, including storage.
- **Keeping the lights on as thermal generation retires.** A key benefit of thermal generation is that it is dispatchable and can be called upon when needed. As thermal generation retires and is replaced with renewables such as wind and solar, replacement dispatchable capacity is needed to ensure electricity is available when consumers need it. One way to encourage capacity to be available is the Reserve Capacity Mechanism ("**RCM**"), which could provide potential payments to dispatchable generators, such as a battery storage, to make energy available to the WEM, particularly during peak periods.
- **Regulating for the future, including developing appropriate access arrangements and market power mitigation measures.** Battery storage can participate in the market as a generator or a load, which raises the question of potential market power, which needs to be monitored within the new WEM market. Estimating the short-run marginal cost ("**SRMC**") for battery storage is complicated, given its charging costs are dynamic in nature and needs to consider opportunity costs, which are driven by future expectations of energy and ESS prices. A key element of incorporating increasing levels of battery storage into the WEM will be understanding the market impact of these technologies on the WEM.

Batteries are key to the WA Government's Energy Transformation Strategy and will help support a reliable and stable electricity system. There are several roles that batteries can play in the WEM's future power system, as shown in Figure 1.

[4] See page 9, https://aemo.com.au/-/media/files/initiatives/wem-reform-program/wem-reform-market-design-summary.pdf

[5] See Table 4, page 7, 2022 Wholesale Electricity Market Electricity Statement of Opportunities, AEMO, June 2022, https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2022/2022-wholesale-electricity-market-esoo.pdf?la=en

Figure 1: Intended role of batteries in the WEM's future power system



Source: Energy Policy WA – Energy Transformation Strategy

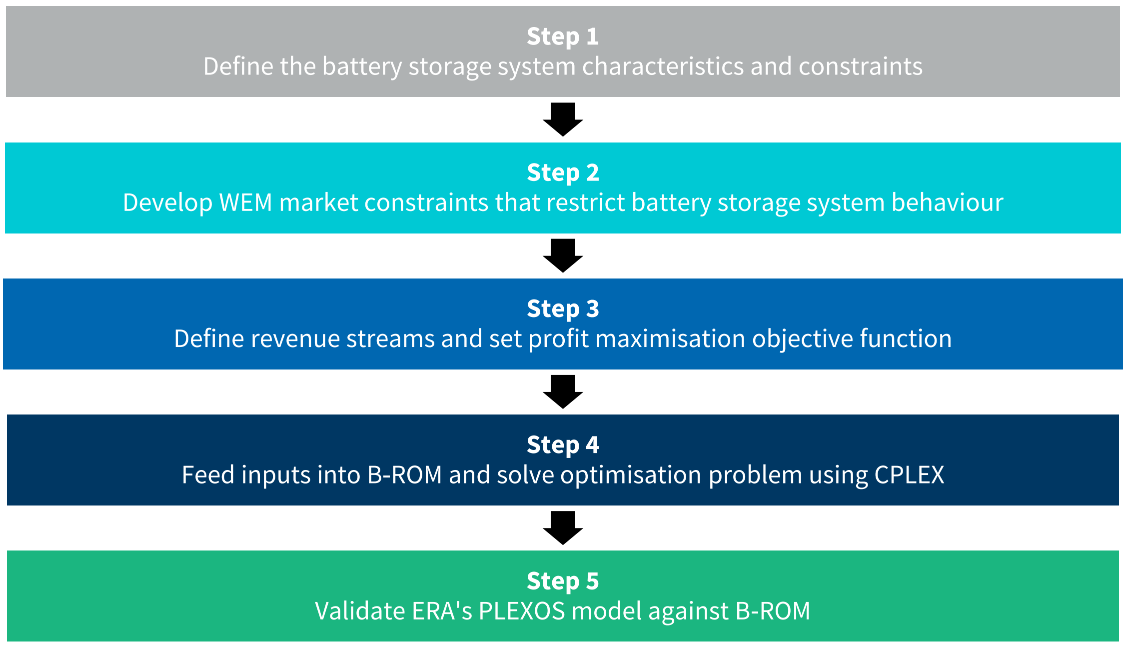
Model for Assessing Battery Storage System Operation and Revenue

Following the WEM reforms, battery storage systems will be able to participate in both the balancing energy market and ESS real time markets ("**RTM**") simultaneously and will seek to maximise revenue across these services. PLEXOS' optimisation equation solves for the lowest system cost to serve energy, which, in most instances, aligns with profit maximising behaviour for individual generators due to their input costs being appropriately considered. However, the SRMC of a battery storage system is complex and PLEXOS can lead to battery storage systems being dispatched inconsistent with profit-maximising behaviour if not properly calibrated. Therefore, FTI have developed a Battery Revenue Optimisation Model ("**B-ROM**") to simulate the dispatch of a grid-scale battery storage system under the new market rules for every 30-minute period in the model horizon.[6]

B-ROM simulates battery operation by optimising across revenues achieved in the real-time energy market and compensation payments for remaining on standby in the ESS markets. While a substantial portion of battery storage revenue may be set under bilateral contracts, bilateral contracting prices will be informed and constrained by expectations of the revenue achievable from trading in the RTM, alongside a floating to fixed price premium. The outcomes from B-ROM are used to validate outcomes from the ERA's PLEXOS modelling and ensure that batteries modelled are operating in a manner broadly consistent with profit-maximising behaviour.

Figure 2 provides a high-level overview of the modelling methodology applied in B-ROM.

Figure 2: High-level process for B-ROM methodology



[6] B-ROM has been developed in Python using IBM's Decision Optimisation CPLEX API, https://www.ibm.com/docs/en/icos/12.9.0?topic=docplex-python-modeling-api

Principles and assumptions

This section outlines the key principles and assumptions used to inform the modelling approach. Observation of batteries operating in the NEM shows that there are several key features of a strategic battery storage system operating in a co-optimised market.

In particular:

- Battery storage operators favour revenue from ESS markets because they are rewarded for availability without necessarily having to dispatch energy in most cases. This reduces battery degradation due to regular cycling.
- Battery storage operators are increasingly moving towards trading platforms with automated algorithms to optimise revenues given the complexity of decision making.
- The marginal cost of a cycle is typically evaluated by prorating the battery replacement cost to the incremental loss of life.

To model battery storage operations in B-ROM, several assumptions have been made as outlined in Table 1.

Table 1: Assumptions and limitations in B-ROM

Assumption	Description	Limitation
Price-taking behaviour	The battery storage system operating in FTI's model receives energy and ESS prices from the ERA's PLEXOS modelling environment. B-ROM optimises battery dispatch without any consideration of the impact on prices.	This assumption restricts us from modelling the impact that the battery is likely to have on the WEM's balancing price.
ESS enablement duration	B-ROM assumes that the battery storage system must have sufficient state of charge to fulfil the ESS requirement for the entire 30-minute trading interval. The current market parameters state that contingency raise services only need to be able to provide the service for 15 minutes and contingency lower services must be able to provide the service for 60 minutes.	This assumption restricts the battery storage system from being able to participate in contingency raise when its charge can sustain between 15 minutes and 30 minutes of discharge. In addition, B-ROM overprovides for contingency lower services when the state of charge can sustain between 30 minutes and 60 minutes of charging.
Lack of ESS competition	B-ROM assumes that the battery storage system can capture all ESS market demand in any trading interval, within the battery's technical limits.	Where competition exists, it is unlikely that a single battery storage system will be able to strategically capture all ESS services available. For example, in a trading interval with regulation raise demand of 100MW, B-ROM assumes the battery storage system can provide all 100MW at the ESS price. However, in reality the battery storage system will compete with other ESS providers and will likely suppress the price to capture all of the revenue or provide only a portion of the requirement.
Simplified cycling cost	Cycling costs have been estimated by calculating a battery replacement cost (based on AEMO ISP's build cost for specific duration) and dividing by the assumed MWh achievable for the life of the battery to arrive at a $/MWh figure.	The rate of battery degradation is complex and depends on depth of discharge and frequency of cycling amongst other factors. These interactions have not been modelled and if accounted for, may further increase the cycling costs relative to the simplified approach.
Rate of Change of Frequency (RoCoF)	B-ROM currently does not assess the value of RoCoF as a revenue stream to the battery storage system	RoCoF is expected to be a future revenue stream available to battery storage systems, and its exclusion is likely to underestimate available revenues. Future versions will include this revenue stream.
Perfect foresight	In B-ROM, the battery storage system has perfect foresight of prices over each two-day optimisation period.	Battery storage system behaviour is based on forecast market conditions (e.g., demand, weather impacting the level of renewable generation available in any given interval), but actual revenue and operation is determined by actual outcomes in real time.
Network Connection Capacity Constraint	In B-ROM, it is assumed that the battery storage system has no binding thermal or stability constraints, but has maximum output at the point of connection.	Battery storage system behaviour and bidding strategies can be considerably influenced by binding constraints at the connection point limiting both export (discharge) and import (charging) capability (e.g., thermal constraints at the connection point can incentivise a battery to charge to alleviate economic/technical spill from co-located renewable facilities or take advantage of negative spot market prices during periods of high renewable generation).
No network charges	B-ROM does not account for network charges associated with charging the battery storage system.	Not modelling the network charge understates the costs associated with operating a battery storage system.
ESS provision dispatch	B-ROM does not assume that any ESS provision is called upon and only enablement payments are modelled.	When offering ESS provision, a battery storage system is rewarded for being on standby through enablement payments. If required to respond to a frequency event, the battery is dispatched (discharged or charged) according to the market requirement and receives a payment for this energy, and this will impact the battery behaviour in

		future periods due to a change in state of charge. These impacts are excluded.

The following section provides a detailed overview of the five steps involved in modelling battery storage system operation in the WEM as summarised in Figure 2.

Step 1: Define the battery storage system characteristics and constraints

The starting point for assessing battery storage system operation and revenue is to define the characteristics of the battery storage system. Table 2 outlines the properties that have been established in B-ROM to define a battery storage system for dispatch optimisation.

Table 2: Battery storage system characteristics in B-ROM

Property	Unit	Description
Power Rating	MW	Maximum power rating of the battery
Energy Capacity	MWh	Maximum energy storage capacity of the battery
Capacity credits	MW	Amount of capacity credits allocated to battery storage system
Initial charge	%	State of charge the beginning of period 1 of B-ROM
Minimum charge	%	Minimum state of charge for battery storage system
Maximum charge	%	Maximum state of charge for battery storage system
Charge efficiency	%	Amount of energy that enters battery storage system for every 1MWh of charge
Discharge efficiency	%	Amount of energy that enters grid for every 1MWh of discharge
Replacement cost	$/kW	Capital cost per kW to replace battery
Lifetime cycles	#	Number of cycles assumed in life of battery

There are several physical constraints on the behaviour of a battery storage system. For example, a battery storage system dispatching at 100 percent of its power rating into the energy market is not able to provide any regulation raise or contingency raise services to the market because there is no capacity for the battery to respond to frequency events if called upon by the market operator.

The following constraints are applied in B-ROM to ensure that the battery storage system dispatches within its technical parameters. All variables in a constraint have been converted to the same unit to ensure correct specification of the constraint, for example, MW and MWh are not being added.

State of charge

Constraint 1: The ending state of charge ("**SoC**") in time *t* is equal to the ending SoC in the prior period (*t*-1) plus any dispatch of the battery in the current period (*t*):

$$SoC_{end_t} = SoC_{end_{t-1}} + (charge_t \times charge\_efficiency) - discharge_t$$

Battery storage system operation

Constraint 2: Discharge operation (including ESS raise enablement) in time *t* must not exceed the power rating of the battery storage system plus any current charging:

$$discharge_t + regulation\_raise_t + contingency\_raise_t \leq power\_rating + charge_t$$

Constraint 3: Charge operation (including ESS lower enablement) in time t must not exceed the power rating of the battery storage system plus any current discharge:

$$charge_t + regulation\_lower_t + contingency\_lower_t \leq power\_rating + discharge_t$$

Constraint 4: Discharge operation (including ESS raise enablement) in time t must not exceed the state of charge of the battery storage system at the beginning of time t:

$$discharge_t + regulation\_raise_t + contingency\_raise_t \leq SoC\_end_{t-1}$$

Constraint 5: Charge operation (including ESS lower enablement) in time t must not exceed the available state of charge of the battery storage system at the beginning of time t:

$$charge_t + regulation\_lower_t + contingency\_lower_t \leq energy\_capacity - SoC\_end_{t-1}$$

Constraint 6: The battery storage system cannot charge and discharge in the same trading interval:

$$charge_t \leq power\_rating \times charge\_flag$$

$$discharge_t \leq power\_rating \times (1 - charge\_flag)$$

where:

$$charge_{flag} = 1\ if\ battery\ storage\ system\ is\ charging, else\ 0$$

Step 2: Develop WEM market constraints that restrict battery storage system behaviour

There are specific WEM market constraints that are reflected in B-ROM, as advised by the ERA. These constraints have been included to ensure that the battery storage system behaves in a way that is consistent with the ERA's assessment of the current WEM operation. A summary of these constraints is included below.

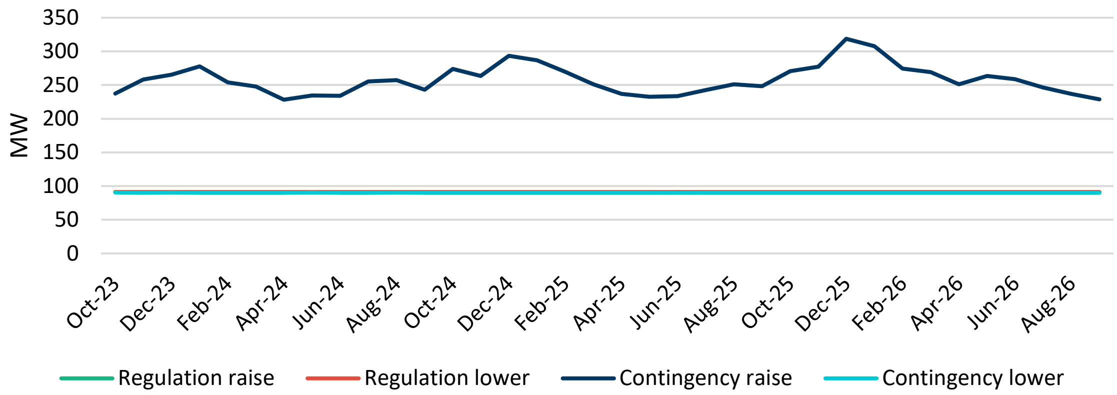
ESS Provision

The B-ROM model is constrained by the assumed level of ESS provision required in the WEM.[7] Average monthly demand for ESS provision is summarised in Figure 3 All ESS services have an average requirement of 90MW per trading interval except for contingency raise which fluctuates seasonally around 250-300MW. Contingency lower has a flat provision of 90MW in every trading interval, whereas regulation raise and lower have a requirement of 65MW from 7.30pm to 5.30am and 110MW for the remaining periods. The implication in B-ROM is that the battery storage system is only able to

[7] ESS market assumptions were provided to FTI by the ERA based on their current view on WEM requirements. These assumptions could be amended for the final report in October 2022.

provide the level of ESS provision that is demanded by the market.

Figure 3: Average ESS market requirement input into B-ROM



Note: Regulation raise and regulation lower requirements are equal to contingency lower and are therefore hidden in the chart

Constraint 7: Regulation services provided by the battery storage system must not exceed market requirements.

$$regulation\_lower_t \leq regulation\_lower\_demand_t$$

$$regulation\_raise_t \leq regulation\_raise\_demand_t$$

In addition, based on current AEMO practice, the provision of contingency raise and lower services is constrained, such that only a percentage (that can vary) of the requirement can be provided by a single generator (and in future potentially also a single battery). For simplicity, the ERA's PLEXOS model has assumed a 30% constraint for all facilities (both generators and batteries) that provide these services and this assumption has been included in B-ROM.

Constraint 8: Contingency services provided by the battery storage system must not exceed 30% of the market requirement.

$$contingency\_lower_t \leq 0.3 \times contingency\_lower\_demand_t$$

$$contingency\_raise_t \leq 0.3 \times contingency\_raise\_demand_t$$

Capacity Mechanism 'Obligation Interval'

A battery storage system that has been assigned capacity credits has an obligation to provide the level of their capacity credits in the energy market for the duration of the obligation intervals,[8] which are assumed in B-ROM to be the eight trading intervals commencing at 16:30pm.[9] For a battery storage system to receive its capacity credit revenue and provide this service, they need to ensure that the level of charge at the beginning of the obligation interval is enough to dispatch energy for the duration of the obligation window.

[8] A facility that fails to meet these capacity credit obligations faces capacity credit refunds.

[9] https://aemo.com.au/-/media/files/initiatives/wem-reform-program/wem-reform-market-design-summary.pdf, page 53

Constraint 9: A battery storage system with capacity credits must have a sufficient state of charge at the beginning of the obligation interval to fulfil the capacity requirement.

$$SoC\_start_{Obligation\ Interval\ Beginning} \geq capacity\_credits \times obligation\_intervals \times 0.5$$

During the obligation interval, the battery storage system must reserve enough energy equal to their capacity credits that they have been awarded for the energy market in case they are required to dispatch. Failure to dispatch if instructed by AEMO incurs a capacity credit refund. Consequently, during the obligation interval, the battery storage system is only able to provide ESS raise services for their remaining capacity.

ESS lower services are unaffected by the obligation interval, other than by the required state of charge. For example, if the battery storage system is required to be fully charged at the beginning of the obligation interval, the battery storage system will be unable to offer any ESS lower services in the first period of the obligation interval unless it discharges in the same period because it is unable to charge.

Constraint 10: The level of ESS raise services a battery storage system can provide during the obligation interval is reduced by the level of capacity credits awarded.

$$regulation\_raise_t + contingency\_raise_t + (obligation_t \times capacity\_credits) \leq power\_rating$$

where:

$$obligation_t = 1\ if\ t\ in\ obligation\ interval, else\ 0$$

Step 3: Define revenue streams and set profit maximisation objective function

The objective of the battery storage system dispatch algorithm is to maximize revenue from participation in the electricity energy and ESS markets, while considering the battery storage system operational costs. Each of the revenue streams in B-ROM are defined below.

Energy Market revenues

Energy "arbitrage" revenue is achieved by utilising battery storage to shift electricity from low-price periods to higher-price periods.

The wholesale electricity price provides a signal to market participants of the value of energy in each settlement period by indicating the level of supply relative to demand at any given time. Low-priced periods suggest that the electricity market has ample cheaply priced energy supply and that there would be benefit to the system of storing and shifting supply to higher-priced periods where excess supply is lower or only high-priced generators are available to provide energy. The battery storage system will achieve a positive revenue from this service when the difference between the average dispatch price and the average charge price exceeds the costs associated with energy storage.

Revenue 1: Revenue achieved from discharging the battery storage system (if participating in energy market)

$$discharge\_revenue_t = energy\_price_t \times discharge_t \times discharge\_efficiency$$

Cost 1: Cost of charging the battery storage system (if participating in energy market)

$$charge\_cost_t = energy\_price_t \times charge_t$$

Cost 2: Cost of cycling the battery storage system – the cost is assigned to both charging and discharging the battery

$$cycle\_cost_t = cycle\_cost \times (discharge_t + charge_t)$$

where:

$$cycle\_cost = \frac{replacement\_cost \times 1000 \times power\_rating}{lifetime\_cycles \times energy\_capacity}$$

Energy Market Revenue:

$$energy\_revenue = \sum_{i=0}^{n} discharge\_revenue_i - charge\_cost_i - cycle\_cost_{\mathrm{i}}$$

ESS Market revenues

ESS markets require capacity and energy to be available to respond to a drop or rise in system frequency within stated timeframes, and for this response to be sustained until frequency is restored to the normal operating range, which typically occurs within ten minutes of a frequency event.

Battery storage systems can receive 'enablement' payments from ESS markets by reserving capacity to be available to respond to frequency events in the electricity market.

Revenue 2: Enablement revenue from providing capacity on standby to respond to drops in frequency

$$regulation\_raise\_revenue_t = regulation\_raise\_price_t \times regulation\_raise_t$$

Revenue 3: Enablement revenue from providing capacity on standby to respond to increases in frequency

$$regulation\_lower\_revenue_t = regulation\_lower\_price_t \times regulation\_lower_t$$

Revenue 4: Enablement revenue from providing capacity on standby to respond to contingency event causing a sudden drop in frequency

$$contingency\_raise\_revenue_t = contingency\_raise\_price_t \times contingency\_raise_t$$

Revenue 5: Enablement revenue from providing capacity on standby to respond to a contingency event causing a sudden increase in frequency

$$contingency\_lower\_revenue_t = contingency\_lower\_price_t \times contingency\_lower_t$$

ESS Market Revenue:

$$\begin{aligned} ESS\_revenue = \sum_{i=0}^{n} & regulation\_raise\_revenue_i + regulation\_lower\_revenue_i \\ & + contingency\_raise\_revenue_i + contingency\_lower\_revenue_i \end{aligned}$$

Objective function

The objective function for different operating modes can then be described as follows:

Energy only: $Max(energy\_revenue)$

ESS only: $Max(ESS\_revenue)$

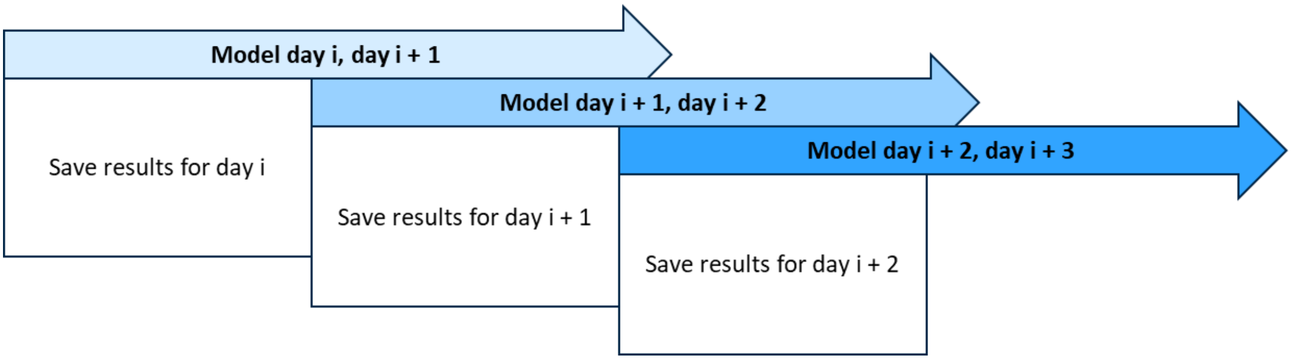
Energy + ESS: $Max(energy\_revenue\ + ESS\_revenue)$

Step 4: Feed inputs into B-ROM and solve optimisation problem using CPLEX

Once all the battery storage characteristics and constraints are defined, B-ROM reads in price data and ESS demand and optimises battery storage operation to maximise the objective function. Price data and ESS demand are exogenous variables to B-ROM.

The model has a one-day look ahead, where battery storage operation is optimised over a two-day horizon (e.g., day t, day t+1) with only the first day result (day t) being saved. B-ROM then rolls the horizon forward one day and repeats the optimisation (day t+1, day t+2), saving results for the first day of the new horizon (day t+1).

Figure 4: Illustrative example of iterative look-ahead process in B-ROM



Step 5: Validate ERA's PLEXOS model against B-ROM

The outcomes from B-ROM are used to validate outcomes from the ERA's PLEXOS modelling and ensure that batteries modelled are operating in a manner broadly consistent with profit-maximising behaviour.

PLEXOS' optimisation equation solves for the lowest system cost to serve energy, which, in most instances, aligns with profit maximising behaviour for individual generators due to their input costs being appropriately considered. However, the SRMC of a battery storage system is complex and PLEXOS can lead to battery storage systems being dispatched inconsistent with profit-maximising behaviour if not properly calibrated. For example, without a proxy for cycling costs, battery storage systems are dispatched for energy during periods where it is unprofitable. This is where B-ROM can be used as a validation tool to check that the dispatch from PLEXOS is appropriate.

Modelling battery storage systems in the WEM using PLEXOS has several benefits:

- **Less workload and ongoing cost for the ERA.** Using native PLEXOS capability allows for a single comprehensive solution for modelling battery storage systems in the WEM. Attempts to integrate B-ROM outcomes into PLEXOS added additional steps that did not enhance model outcomes. Our testing to date has demonstrated that significant time is needed to iterate between B-ROM and PLEXOS, particularly when there are multiple batteries. These additional steps would need to be repeated every time a change is made in the PLEXOS model. In addition, the ERA would need to maintain an additional model to ensure it continues to be relevant.
- **More robust market modelling outcomes.** Battery storage systems operating in PLEXOS are not price takers, and as such competition between battery storage providers is captured within the modelling. As seen in the preliminary results discussed in this report, additional battery storage systems in PLEXOS suppress ESS prices, which leads to more robust modelling outcomes when using PLEXOS.
- **Responsiveness to market dynamics.** The influence of changes in market dynamics on battery storage behaviour will be captured in the PLEXOS modelling environment more accurately. For example, battery storage outcomes will be influenced by changes in gas prices, thermal retirements and increased renewable penetration. PLEXOS will capture these factors dynamically.

- **Better captures profit-maximising behaviour for BESS.** PLEXOS achieves better revenue outcomes for battery storage systems due to the ability to optimise behaviour in response to all market dynamics. B-ROM takes prices and provides a battery storage profile that is exogenous to the model. This profile does not achieve the highest profit for the battery storage system because it does not capture the impact of battery behaviour on prices, and therefore does not represent profit-maximising behaviour.

Due to these considerations, it is recommended that PLEXOS is used to model battery storage systems in the WEM, and that B-ROM is used to externally validate the behaviour of individual battery storage systems, as demonstrated below.

Comparison of B-ROM and PLEXOS results

To validate the results of the ERA's PLEXOS model, monthly net profit for the battery storage system from PLEXOS is compared to the monthly net profit from B-ROM. The results for the first year of the model horizon are outlined in Table 3.[10] As shown, in almost all months, the PLEXOS model is calibrated in such a way that the battery storage system achieves over 90 percent of the revenue from optimisation in B-ROM.

Table 3: Comparing monthly net profit for battery storage system

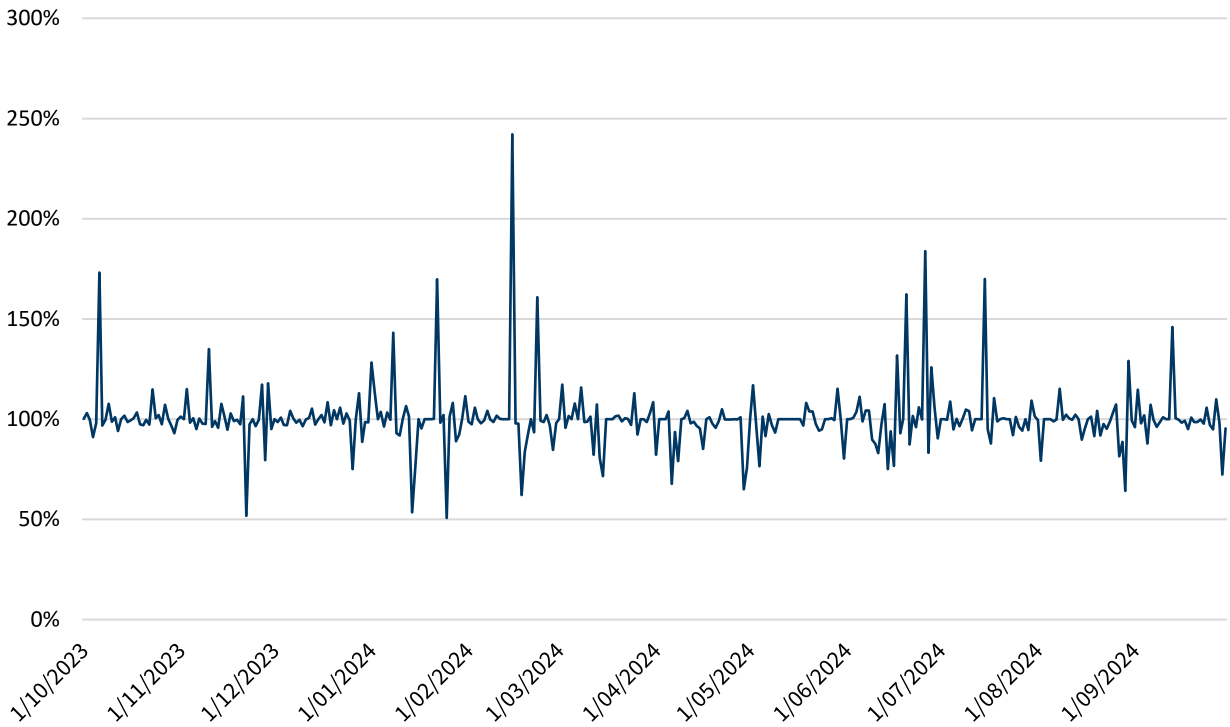
Month	PLEXOS	B-ROM	Convergence
Oct-23	2,054,709	2,060,271	99.73%
Nov-23	1,559,290	1,578,848	98.76%
Dec-23	1,251,993	1,258,747	99.46%
Jan-24	961,782	1,090,215	88.22%
Feb-24	792,095	848,066	93.40%
Mar-24	808,343	809,444	99.86%
Apr-24	1,011,795	1,071,618	94.42%
May-24	506,052	545,208	92.82%
Jun-24	271,395	272,326	99.66%
Jul-24	530,011	529,643	100.07%
Aug-24	1,029,940	1,036,544	99.36%
Sep-24	2,061,787	2,116,302	97.42%

On a daily level, there is more variance in the results as shown in Figure 5. It should be noted that the convergence percentage is highly sensitive to the level of revenue achieved on the day, with lower revenue days overstating the difference in revenue. For example, 15 February 2024 has a convergence percentage of 242%, however the absolute dollar differential is only $2,500 for this day and results from B-ROM carrying a lower state of charge into the day and needing to charge the battery storage system at $30/MWh to enable it to provide ESS services.

Conversely, there are some large dollar discrepancies that are understated due to the high level of revenue earned on a particular day. For example, 25 January 2024 has a convergence percentage of 51% and an absolute revenue difference of $65,000. This is driven by a spike in ESS raise prices to over $1,200/MWh for a single trading interval due to a shortage of reserve availability. In PLEXOS, the battery storage system is dispatched at 100 MW for ESS raise services. B-ROM has no visibility of the availability of reserve in the WEM and therefore sees an opportunity to charge at 100 MW to capture 200 MW of ESS raise services. Consequently, the battery storage system makes almost double the revenue on this day. However, it is unlikely that the system operator would schedule this operation, given its objective to minimise system costs, which would be increased by adding additional load (the battery system charge load) at a time of system stress. Therefore, we consider these infrequent events to be a feature of 'optimisation' without visibility of market conditions, which doesn't reflect real-world outcomes. To address this, one option could be to preclude battery operation in the energy market from increasing the level of ESS provision above nameplate capacity when ESS prices exceed a pre-determined threshold in B-ROM.

[10] A comparison of results for the full three-year modelling horizon will be provided in the final report in July 2022.

Figure 5: Daily convergence between PLEXOS and B-ROM for battery storage revenue



Results

This section contains a summary of the draft results from modelling undertaken in B-ROM. The results outlined below are based on a preliminary case study of a 100 MW, 2-hour duration (200 MWh) battery storage system, which is assumed to be operational prior to the model horizon start date of 1 October 2023.

Battery storage system characteristics

Table 4 outlines the properties assumed for the case study simulation in B-ROM. The model horizon for this run is based on the first three years of the new WEM.

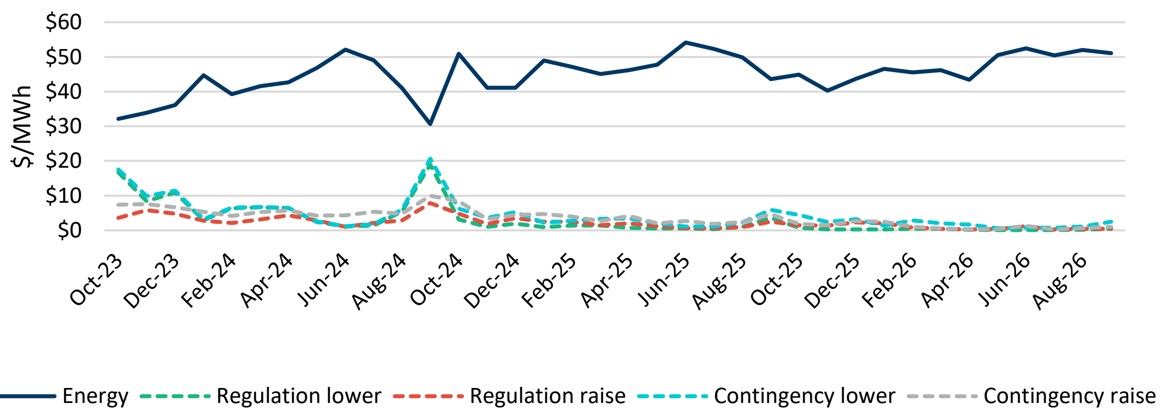
Table 4: Battery storage system characteristics for Case Study example

Property	Case study
Model horizon start date	1 October 2023
Model horizon end date	30 September 2026
Power Rating	100 MW
Energy Capacity	200 MWh
Capacity credits	46 MW[11]
Replacement cost	$572/kW[12]
Lifetime cycles (20 years)	7,300[13]

Energy and ESS price inputs

Results from B-ROM are highly dependent on the energy and ESS prices that are inputs into the model.[14] Figure 6 shows average monthly prices that have been fed into B-ROM from the ERA's PLEXOS model. As shown, energy prices average between $30 and $60/MWh over the model horizon. Average ESS prices in the model are initially high, around $30/MWh for lower services and $15/MWh for raise services and move towards zero in 2026. The downward price trend is driven by the introduction of additional batteries to the WEM without an increase in the ESS requirement.

Figure 6: Average monthly energy and ESS prices input into B-ROM



11 AEMO Services Limited, Assignment of Capacity Credits 2022
12 AEMO Services Limited, ISP 2021 – inputs and assumptions
13 Aurecon, 2020 Costs and Technical Parameter Review Consultation Report, https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/aurecon---cost-and-technical-parameters-review-2020.pdf?la=en
14 FTI Consulting have not validated the methodology and results of the ERA's PLEXOS model, including the underlying assumptions.

Overview of results

B-ROM optimises battery storage revenues based on several different operating modes. Table 5 summarises the net revenue achieved by the battery storage system under each of these.

Table 5: Summary net revenue based on different operating modes in B-ROM

Model	Q4 2023	CY 2024	CY 2025	Q1-Q3 2026	Total
Energy arbitrage only	$1.26m	$2.92m	$1.71m	$0.70m	$6.59m
ESS only	$3.95m	$8.33m	$3.53m	$0.91m	$16.72m
Energy + ESS	$4.47m	$9.33m	$4.37m	$1.46m	$19.64m
Energy + ESS + capacity credit obligation (excl. capacity credit revenue)	$4.27m	$8.65m	$3.78m	$1.22m	$17.92m

When the battery storage system only participates in energy arbitrage, or only in ESS markets, it achieves a total net revenue of $6.59 million and $16.72 million, respectively, across the three-year model horizon. In comparison, the battery storage system achieves net revenue of $19.64 million across the model horizon by participating in both markets. This demonstrates the benefit to the battery storage system of co-optimising its revenue across both energy and ESS.

Including the capacity credit obligations reduces overall ESS and Energy revenue by ~$1.7 million across the model horizon due to the restrictions around state of charge at the beginning of the obligation intervals and the reduced availability for raise services. This revenue excludes any capacity credit payments, which, if adequately priced, would see overall revenue for the battery be higher than Energy + ESS revenue.

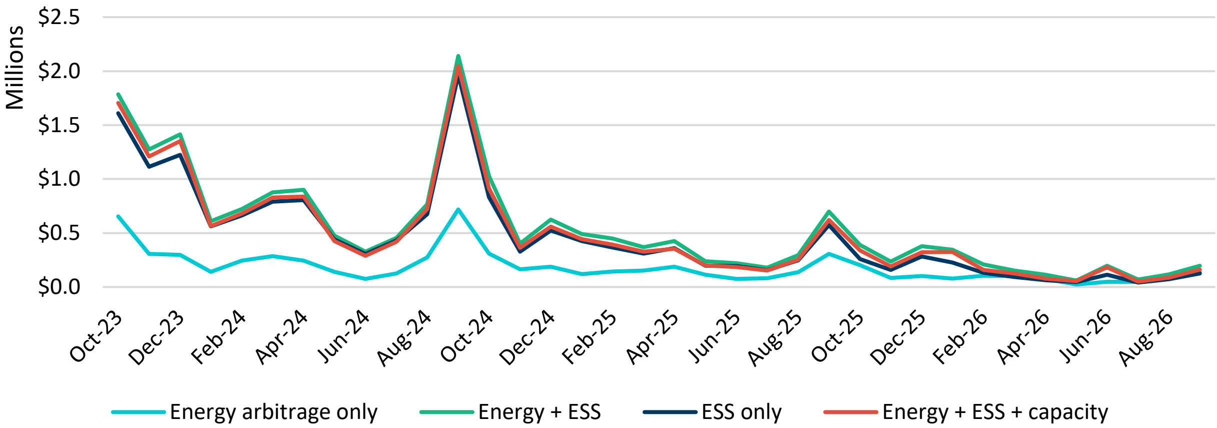
Figure 7 tracks the average monthly revenue for each of the operating modes. Except for September 2024 and 2025, revenue across all three modes declines due to reducing ESS prices and energy price spreads.

This trend is particularly pronounced for ESS revenue where prices are forecast to fall towards the end of the model horizon, driven by additional competition for ESS services as additional batteries enter the WEM.

The peak profits observed in September 2024 are likely due to two reasons:

- Average time weighted price spread in September 2024 is ~$160/MWh relative to $80/MWh prior to October 2024. This leads to higher energy arbitrage revenues. There could be multiple reasons for higher price spreads in the balancing market. Some examples include unplanned/planned outages for thermal generators leading to energy tightness, increased penetration of Solar PV and Wind leading to low energy prices at certain times in the day, and the SRMC spread for peaking generators (Gas) increasing due to higher gas prices.
- Increased average monthly prices for ESS services primarily for contingency and regulation lower prices. This is likely driven by minimum operational demand conditions because of both high penetration of utility and small scale (DER) solar PV.

Figure 7: Monthly net revenue based on different operating modes in B-ROM



To demonstrate the behaviour of the battery storage system, Figure 8, Figure 9 and Figure 10 show the output of the battery storage system as optimised in B-ROM for a sample day (3/09/2024) in Energy + ESS operating mode.

Figure 8: Energy and ESS prices for sample day (3/09/2024)

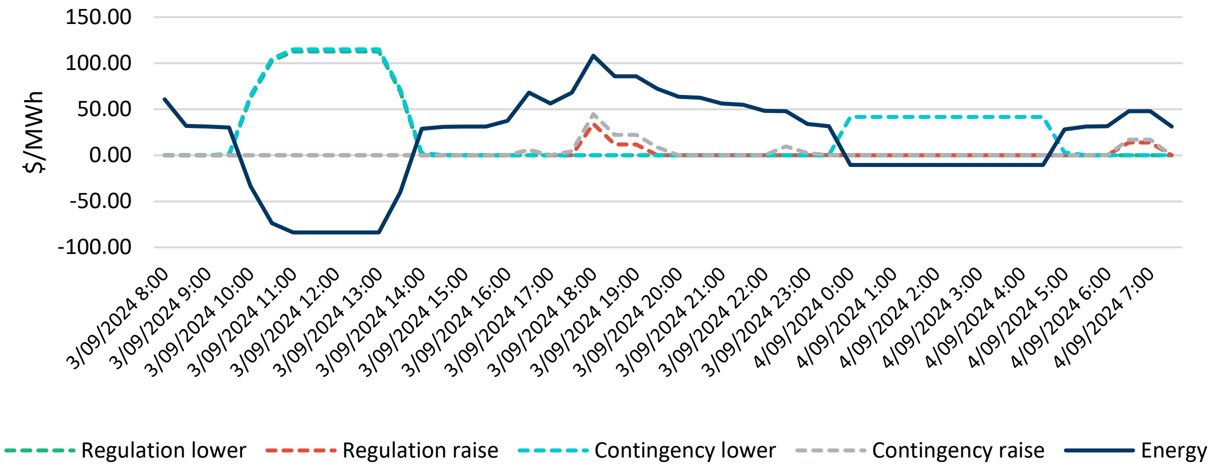


Figure 9: Battery storage system optimisation in Co-Optimisation mode from B-ROM for sample day (3/09/2024)

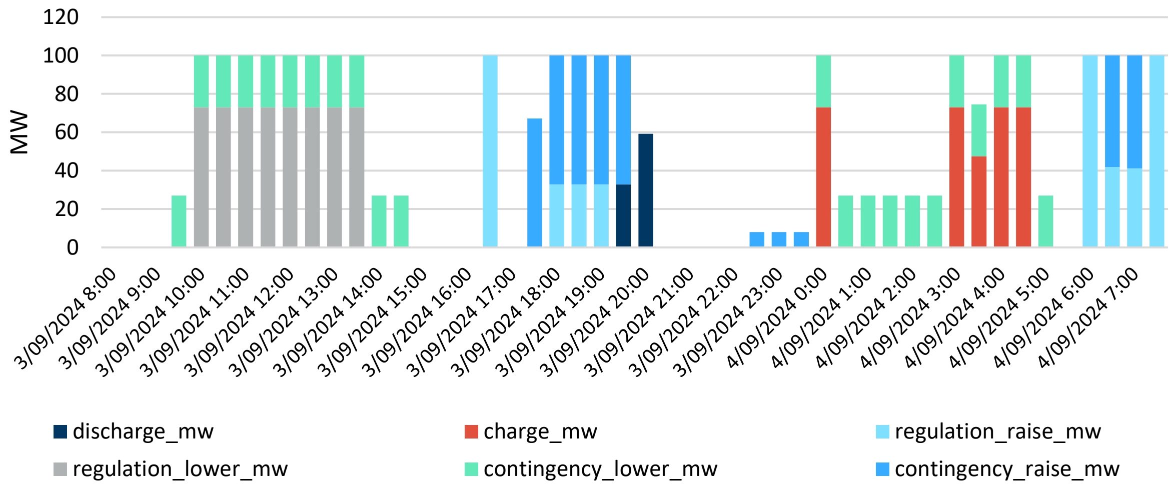
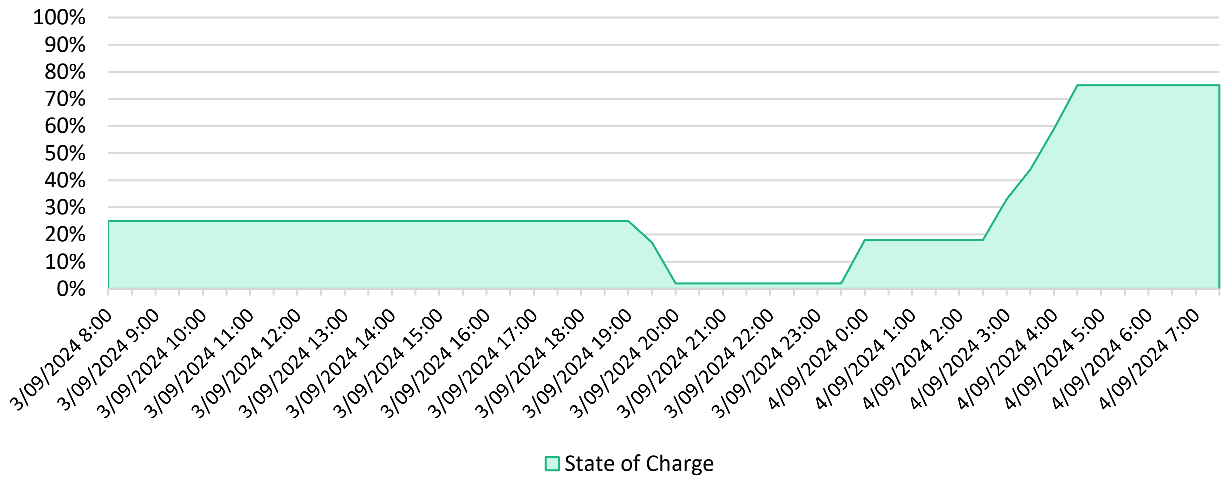


Figure 10: Battery storage system state of charge in Co-optimisation mode from B-ROM for sample day (3/09/2024)



On this day, there are several key behaviours that can be identified to demonstrate how the battery storage system prioritises ESS market participation over the energy market:

- **10.00am – 1.30pm:** There is a sustained period of negative prices in the middle of the day from 10am to 1.30pm, driven by high solar generation. During this time, a reduced amount of operational dispatchable generation leads to elevated regulation lower and contingency lower prices. This is because an unforeseen reduction in load would require generation to quickly reduce to avoid frequency rising above safe limits and there is limited generation that can respond to this request. B-ROM dispatches the battery storage system for ESS provision during these times because receiving the enablement payment outweighs the benefit of charging at typical negative prices (between $0 and -$70/MWh).
- **5.30pm – 8.30pm:** The energy price peaks for the day above $80/MWh from 6.00pm to 7.30pm. During this period, regulation and contingency raise prices rise because there are relatively few generators on standby to respond if another generation unit trips. B-ROM prioritises the battery storage system for ESS enablement payments to capture the revenue without incurring cycling costs, and only dispatches the battery storage system for energy once the ESS prices fall back to zero. The battery storage system then dispatches all its available energy at an average price of $66.50/MWh, which is below the highest energy price for the day.
- **12.00am – 7.30am:** For the battery storage system to participate in ESS raise markets, it needs to have enough charge in the battery to be able to dispatch if called upon. From 6.00am onwards, both regulation and contingency raise prices rise above zero. To ensure the battery storage system has enough charge to offer into these markets, B-ROM charges the battery overnight to bring the state of charge to close to 80 percent.

Appendix A shows the behaviour of the battery storage system when participating in the energy market only (i.e., disabled for ESS services) for comparison.

Key revenue stream insights

FTI's modelling highlighted the following key insights into battery storage system operation strategy in the WEM:

- **Current price spreads in the energy market are too low for a battery to make adequate revenue**. Due to the costs associated with cycling the battery storage system and relatively assumed low price spreads in the WEM, a battery storage system is not expected to make much of a return from energy arbitrage. Arbitrage revenue is typically high when scarcity pricing exists with extremely high price spreads incentivising battery storage to preserve energy for low-supply periods. This is not a feature of the WEM given its design includes a balancing price cap alongside a capacity market.
- **ESS revenue contributes to reducing the required spread in the energy market however, these profits can collapse substantially in a short timeframe with increased saturation of battery projects weakening the investment signal**. Almost all battery storage system revenue comes from ESS markets initially before ESS market prices fall towards zero in the later years of modelling horizon. In this market, early battery movers capture the most lucrative revenue streams and possibly erode value for other future battery storage system projects.
- **Revenue diversity and certainty is important**. While revenues from ESS and energy markets are currently quite lucrative only for the upfront years, capacity payments provide long-term certainty for investors looking for stable returns. However, the obligations associated with capacity market participation reduces the revenue achieved by the battery storage system during the obligation intervals and this opportunity cost must be reflected in the capacity payment price.
- **Energy arbitrage and ESS revenue is highly correlated with long term market value drivers**, including wind and solar PV penetration.

Current price spreads in the WEM's energy market are too low for a battery to make adequate revenue

Energy arbitrage revenue increases with price volatility because the battery storage system can take advantage of the price spread, provided the difference between charge cost and discharge revenue is larger than efficiency losses and the cost to cycle. The amount of energy cycling in B-ROM is sensitive to the assumed charge efficiency, discharge efficiency and cycle cost of the battery storage system.

In our case study, we have assumed a replacement cost of $572/kW and 7,300 cycles over the lifetime of the battery storage system. For a 100MW battery storage system, this equates to a $39.20/MWh cost to cycle. This replacement cost in B-ROM simulates the opportunity cost of energy cycling and incentivises the battery storage system to reserve energy for high price spreads that enable it to recover its costs.

Figure 11 compares the average monthly price spread achieved for a battery storage system operating in the energy arbitrage market only against the time weighted average price spread. The time weighted average price spread is the monthly average price spread across the highest four trading intervals and lowest 4 trading intervals for each day (assuming a 2-hour duration battery). Most notably, the average price spread from October 2023 to October 2024 is ~$80/MWh and above, and during this time we see higher levels of energy discharging when operating in energy arbitrage only mode. However, from September 2024 onwards, there is a shift in price spread that sees the average daily price spread rarely exceed $80/MWh and drop towards $60/MWh in 2026. In most instances, the battery storage system operating in energy only mode optimises its discharge and achieves a higher average price spread than the time weighted average price due to its ability to not cycle energy on days with low price spreads. However, the lack of price volatility in the WEM is a feature that results in low energy arbitrage revenues for a battery storage system.

Figure 11: Monthly dispatch-weighted average price spread achieved compared to time-weighted average price spread

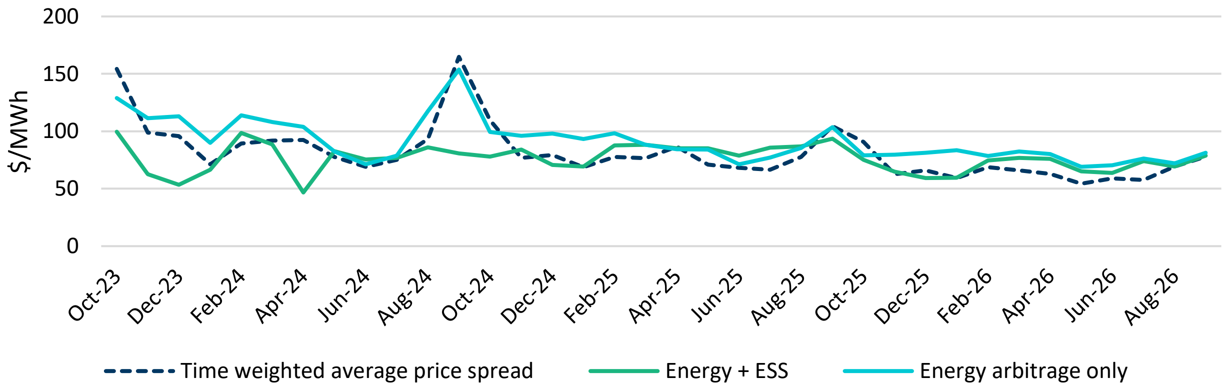
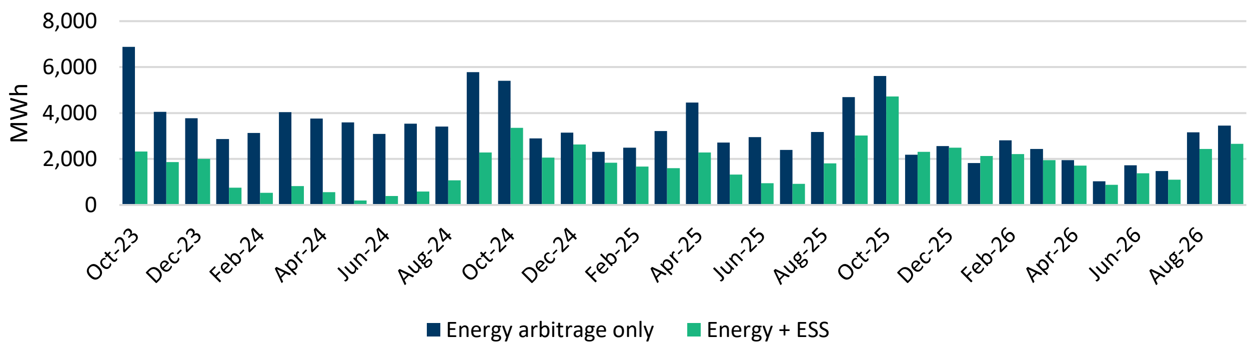


Figure 12 demonstrates the monthly discharge for two different operating modes. Consistent with the average price spreads in Figure 11, the battery storage system discharges more regularly when there are higher price spreads prior to 2026. In addition, participation in the ESS markets sees the battery storage system reduce the level of participation in the energy market to extract the most value possible.

Figure 12: Average monthly discharge in B-ROM

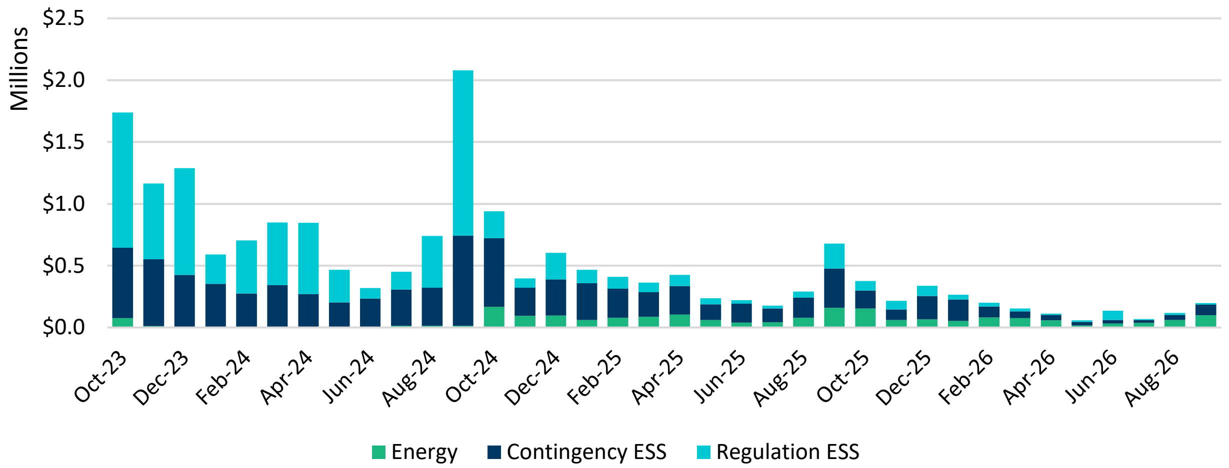


ESS revenue contributes to reducing the required spread in the energy market; however, these profits can collapse substantially in a short timeframe with increased saturation of battery projects weakening the investment signal.

Consistent with observations of battery storage system behaviour in the NEM, B-ROM optimises revenue by predominantly participating in ESS markets. Figure 13 shows the split of revenue achieved by the battery storage system, with 89 percent of revenue modelled coming from ESS market participation over the horizon. The ESS market provides a key revenue stream for the battery storage system that reduces the reliance on high price spreads to make revenue.

However, with the forecast decline of ESS prices because of an assumed increase in competition in the ERA's PLEXOS model (additional battery storage system projects enter the WEM within the model horizon), the level of revenue achieved in ESS markets reduces substantially and shifts towards energy arbitrage. Notably, while ESS prices remain high prior to October 2024, there is almost no revenue attributed to energy arbitrage. This is because high ESS prices reduce the incentive for the battery storage system to participate in the energy market. However, once ESS prices fall away, more of the battery storage system capacity is utilised to take advantage of price spreads.

Figure 13: Monthly revenue across energy and ESS markets



Revenue diversity and certainty is important

In the initial years of the modelling horizon, revenues from ESS markets are quite lucrative due to high market prices, however these drop away substantially towards the end of the horizon. This highlights the risks associated with an undiversified revenue stack for a battery storage system with reliance on ESS market revenue resulting in decreasing profitability. In the case study, the energy market provides an additional revenue source for the battery storage system, which improves its income, however, due to the absence of large price spreads in the WEM, this revenue is minimal. To encourage the uptake of battery storage in the WEM, it is important that all the features of a battery storage system are considered when developing participation models for battery storage to provide system benefits. Table 6 provides some examples of the services that batteries can provide to an electricity system that are not modelled in B-ROM but a battery storage system could seek to provide through contracts or other payment mechanisms.

Table 6: Examples of additional revenue streams not included in B-ROM

Service	Description
Fast frequency response (FFR)	Battery projects have identified a capability to respond much faster (response times of typically 100 – 250 ms) than is required by the minimum timeframe contingency markets. In the NEM, The AEMC has already identified this as a potential market reform with implementation of the FFR market locked in by 2023/2024.
Voltage control and system strength	Although technically possible, provision of this service is complex (dependent on local network needs and negotiated agreements with the Network Service Provider) and additional inverter capacity above typical network connection performance requirements would likely be required.
System Restart	Most utility-scale generation requires some electricity from the grid to start up. If all generation is lost (a very rare occurrence), black start capability allows the power system to be restored by starting specifically enabled generators. Hydropower, both conventional and pumped hydro, are well-placed to provide black start services if suitably incentivised. In recent years, it has also been successfully demonstrated that battery-based energy storage can achieve this as well.
System integrity Protection Scheme (SIPS)	Schemes to protect interconnectors for the purposes of operating as close to their maximum transfer capability (physically) could be implemented in future. The scheme is designed such that different system security objectives can be met. For example, rapid injection of active power by the battery acts as backup in case the interconnector trips) to increase the thermal rating of an interconnector under normal operating conditions
Virtual transmission line	Strategically placed storage also has the potential to be able to defer transmission and distribution upgrades, by reducing peak utilisation. The nature of this opportunity is very site specific and is expected to mainly be applicable to smaller capacity storage systems, scaled to suit the existing transmission or distribution line; nevertheless, it is a benefit that some storage opportunities can provide that is difficult to monetise in the existing market. One such application is the virtual transmission line, which at its simplest, consists of two BESS systems at either ends of a transmission line — operating in tandem with one system charging, the other discharging, to enable more efficient use of existing transmission lines and thereby alleviate current and future limitations.
Synthetic Inertia	With the right incentives, synchronous storage technologies such as batteries with grid forming inverters could also be configured to operate as a synchronous condenser and thus provide inertia even when not generating. Inertia makes the power system more robust to sudden changes in the balance between supply and demand. Inertia suppresses and slows frequency deviations such that automatic frequency controls can respond and return the system to balance. A Rate of Change of Frequency (RoCoF) service is being introduced to the WEM to provide payments to this service.
Integrate renewable energy (firming)	New products are likely to emerge in the WEM to address the changing market characteristics with increasing penetration of variable renewable energy. Firming contracts are an example of these new products and would aim to complement wind and solar by providing coverage when variable renewable energy output is low or zero. At the right price, firming contracts may be attractive to a wide range of buyers., For example, the contracts could provide a consumer access to stable energy costs or a renewable energy developer the ability to on-sell swap contracts from variable energy sources.
Curtailment management	Use of DC and/or AC coupled batteries to manage technical (network constraints) and economic spill increasing the capacity factor of co-located renewable energy facilities.

There is also a high level of uncertainty surrounding the forecasting of energy and ESS prices. In particular, ESS market prices are difficult to predict since they will be set based on co-optimisation with energy for the first time under the new WEM market. This creates difficulty in getting battery storage projects off the ground, as there is a risk of being unable to recover capital costs.

Capacity payments provide a revenue stream to a battery storage system that is more stable, which improves long-term certainty for investors seeking less volatile returns. However, capacity mechanism participation shifts the behaviour of the battery storage system and the opportunity cost must be reflected in the capacity payment price. Taking the same sample day (3/09/2024) employed above as an example, the battery operates in a substantially different manner than when in Energy + ESS mode, as shown in Figure 15 and Figure 16 and discussed below:

- **10.00am – 1.30pm:** The battery storage system behaves in the same manner as the Energy + ESS operating mode, except it charges in the last interval of negative prices to ensure that the state of charge is sufficient prior to the obligation interval.
- **5.30pm – 8.30pm:** During the obligation interval, the battery storage system is restricted to only be able to provide 54 MW of ESS raise services (100 MW capacity less 46 MW capacity credits). The battery storage system maximises this available provision in the contingency raise market. Because the capacity credits restrict the remaining 46 MW from capturing ESS revenue, the battery storage system discharges at 46 MW to capture the energy market revenue until the state of charge reaches its minimum.
- **12.00am – 7.30am:** The battery storage system behaves in a similar manner to the Energy + ESS mode, however it takes the state of charge higher in anticipation of holding enough charge for the following day's obligation interval.

Figure 14: Energy and ESS prices for sample day (3/09/2024)

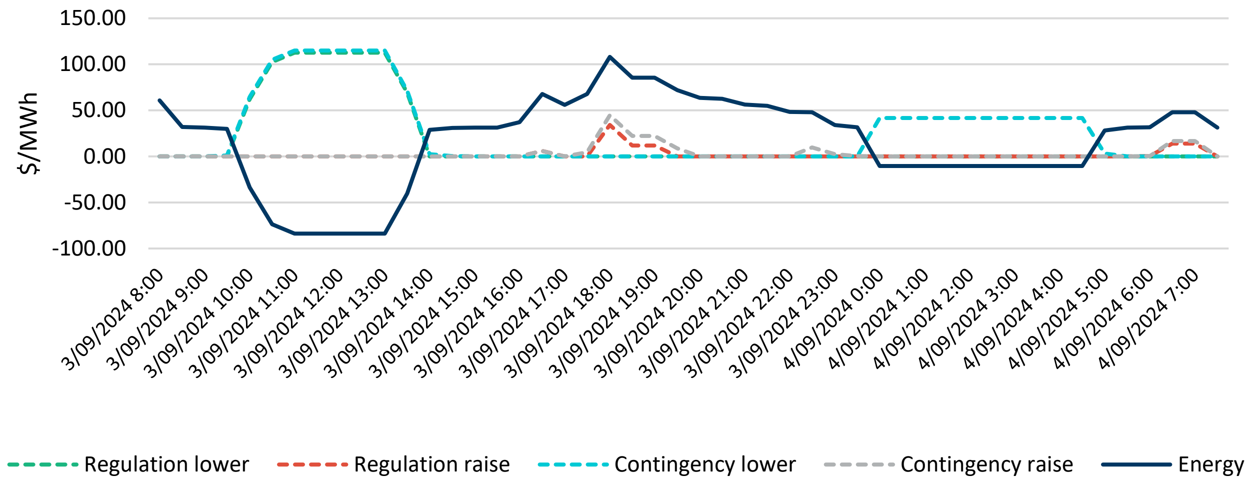


Figure 15: Battery storage system optimisation in Energy + ESS + Capacity mode from B-ROM for sample day (3/09/2024)

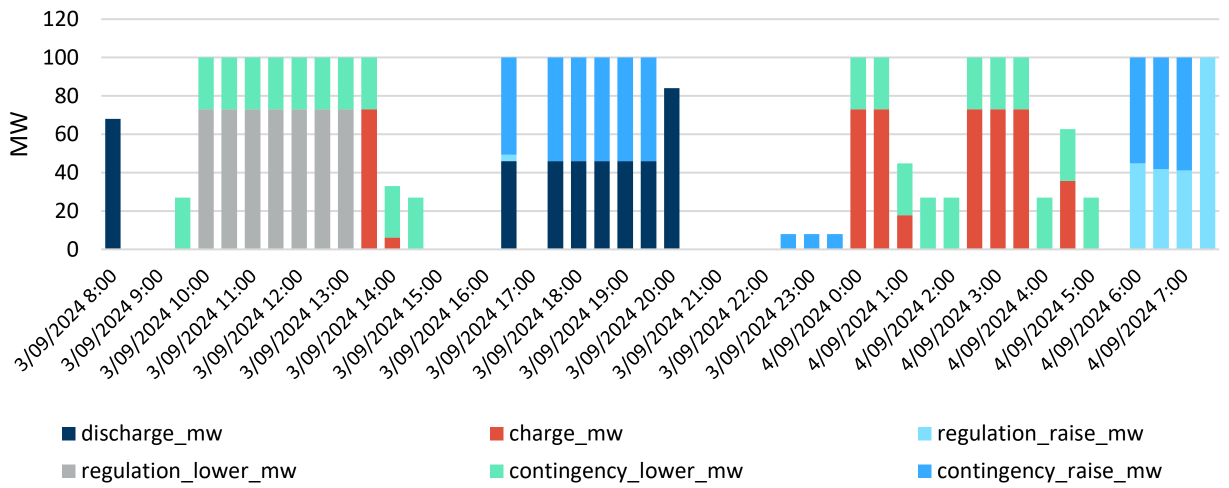
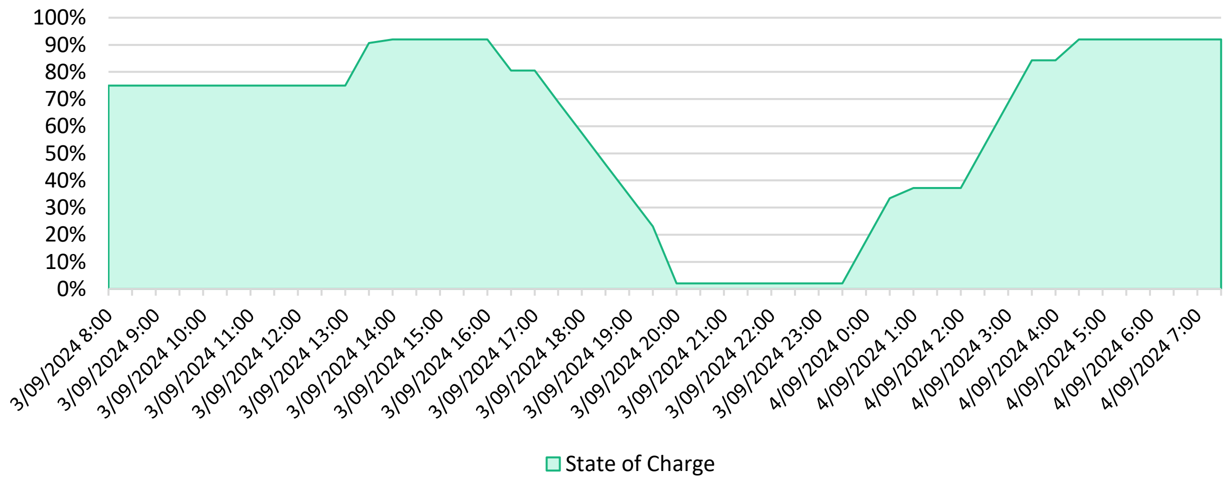


Figure 16: Battery storage system state of charge in Energy + ESS + Capacity mode from B-ROM for sample day (3/09/2024)



Energy arbitrage and ESS revenue is highly correlated to long term market value drivers

There are several competing factors that can impact energy and ESS market prices, and in turn, the battery storage system revenue. Due to the highly sensitive nature of B-ROM to the input prices and ESS demand, it is important to note the drivers that can shift these inputs in either direction. Table 7 provides an overview of some of the important factors that impact battery storage system revenues based on their impact on energy and ESS prices.

Table 7: Key long-term value drivers for battery storage system revenue streams[15]

		Component			
	Key value driver	Price spread	Value of Lost Load	Contingency ESS	Regulation ESS
(+) correlated	Increased wind penetration	↑			↑
(+) correlated	Increased solar PV penetration	↑		↑	↑
(+) correlated	Higher thermal generation fleet age (e.g., trip likelihood)		↑	↑	
(+) correlated	Higher SRMC spread of generators (e.g., gas)	↑	↑		
(+) correlated	Shift to 5-minute settlement	↑	↑		↑
(+) correlated	Higher average temperatures		↑	↑	
(-) correlated	Higher storage asset penetration (e.g., battery storage system)	↓	↓	↓	↓
(-) correlated	Improved transmission capability	↓	↓		
(-) correlated	Improved load/supply predictability				↓
(-) correlated	Advanced fast response technology			↓	↓
(-) correlated	Improved primary frequency response			↓	↓

Consequently, there is an incentive to be a first mover in the WEM battery market, given the forecast of high initial ESS market prices that decrease as additional storage is added to the market. Given there are bidirectional pressures that will influence prices in the future, long-term certainty over revenue is low.

[15] Positively correlated value drivers that lead to an increase in the market component are indicated with a green box and an up arrow. For example, increased wind penetration is expected to lead to higher price spreads in the WEM and higher regulation raise and lower prices due to the imperfect nature of wind generation forecasting.

Preliminary Stakeholder Consultation

Process for preliminary stakeholder engagement

The stakeholder engagement process that was undertaken, included consulting with battery operators in the NEM, WEM and other electricity markets including the US, and the UK individually.

The primary purpose of the stakeholder engagement was to:

- Seek confidence in battery bidding strategies being modelled that will involve maximising revenues in one or multiple markets subject to various constraints, including loss value from degradation and capacity obligations. Stakeholders were consulted to provide input based on operational experience of existing batteries in their respective markets including aligning the input on strategies to WEM characteristics.
- Present preliminary modelling results and seeking high level principal validation and feedback on the proposed outcomes of profitability assessment.

Feedback received and next steps

The feedback received from the consultations may be considered across three key areas.

The investment case for batteries in the WEM remains difficult

It is currently unclear what batteries can expect or forecast for ESS in the WEM market in general. This inherent uncertainty of prices in ESS markets means that battery revenue is likely to be highly volatile and difficult to quantify and forecast for investors presenting a barrier to gaining finance.

Moreover, as the WEM is a much smaller market than the NEM, additional batteries entering the market will have a big impact on both energy and ESS prices. Batteries are likely to erode the value obtained from each other, meaning that first movers will have the upper hand and resulting revenue forecasts will quickly change.

Stakeholders also flagged that investment in batteries in the WEM is still primarily reliant on ARENA or other funding. This is largely due to the lack of certainty of the future of ESS markets and predicting "peaky" events that form a considerable portion of the revenue. Stakeholders noted that the current high demand for battery technology across most energy markets coupled with global hyper-inflationary market conditions means that capital costs for battery storage systems are rising in the short term.

Preliminary results largely align with battery storage system operators' expectations of behaviour

There was a general consensus from stakeholders that the preliminary results aligned with their expectations, particularly that ESS would be the main source of revenue. Energy arbitrage would likely be limited due to shallow price spreads in the WEM (maximum STEM price for non-liquid fuel generators $290/MWh)[16]; especially when compared to the NEM due to the higher price cap.[17] The results also aligned with the expectation that the battery will participate in the RCM, provided the price for capacity credits remains sufficiently high.

There were some concerns raised on the limitations of the modelling, particularly in relation to the lack of utilisation of ESS dispatch. Only enablement payments are included in the model, however payments for the delivery of ESS services are provided in addition when dispatched by AEMO. It was noted that regulation services are called upon more than contingency, approximately 15 percent versus 1 percent of the total enablement period, respectively.

Storage can exercise market power, particularly in congested areas

If storage is centralised in a congested part of the network, it may aggravate congestion and providers located in that part of the network may not receive their full expected allocation due to network access quantity ("**NAQ**"). Stakeholders noted that market power

[16] https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/data-wem/price-limits

[17] Currently $15,100/MWh increasing to $15,600/MWh as of 1st July 2022 - https://www.aemc.gov.au/news-centre/media-releases/2022-23-market-price-cap-now-available

mitigation is usually done by assessing how a generator bids compared to its short-run marginal cost (“**SRMC**”), however, batteries are complex and SRMC is not a simple input because it is based on opportunity costs of discharging energy at a time where the economic value is likely to be higher, charging costs, degradation and round-trip efficiency.

Battery investment framework

Emerging challenges associated with lack of investment in batteries that can act as flexible generation

Given sustained prolonged investment in renewable energy plants, with intermittent generation to meet emission reduction targets and a current plant mix which is inflexible, the risks of not investing in storage type assets, such as batteries, could include the following:

- Emerging reliability issues, including increased likelihood of unserved energy in some trading periods due to inflexible plant not being able to ramp up generation sufficiently to meet demand. Alternatively, additional inflexible plant may need to be operational out of the merit order in the energy market to provide Essential System Services, which increases costs to the market and ultimately to customers. This is evident given that the WEM has the highest ancillary services cost in the country by a large margin.[18]
- Increased frequency of negative prices when output from utility scale renewable generation is high, and operational demand is low with high levels of DER (rooftop PV) penetration.
- Increased dispatch advisories by regulators and energy market operators when certain situations have potential Power System Security ramifications. As an example, this has been observed within the NEM to maintain system security, with growing renewable energy generation and ageing thermal fleet. Total NEM system costs have considerably increased to keep the system stable. The costs primarily include Frequency Control Ancillary Services ("**FCAS**"), compensation for directing generators to continue to operate or avoid curtailment, as well as the Reliability and Emergency Reserve Trader ("**RERT**"). Overall, quarterly system costs have increased to 8 percent of the energy costs, relative to typically being 1-2 percent each quarter. These costs are eventually borne by consumers and there is a risk that low investment in flexible generation in the WEM could result in similar rises in system costs.
- Increased use of Demand Side Management resources or strategic energy reserves to address supply shortfalls, which can be expensive, as they are typically only used as a last resort measure in the WEM (i.e., they have high fixed costs and low variable costs).
- Increased energy and ESS prices if inflexible plant exits in the system (due to age or low economic returns) and is not replaced with flexible generation and storage systems. The installed flexibility can be incentivised by the Reserve Capacity Mechanism ("RCM"), but it does not necessarily guarantee operational availability and economic efficiency of delivering this flexibility in real time when required.

Unlocking investment in batteries for a future WEM

Least-cost modelling, such as the Whole of System Plan ("**WoSP**") modelling, shows that a considerable amount of batteries is required to minimise the cost of replacing retiring thermal generation. However, while batteries would provide substantial value to the market, it is unclear how much of that value will be captured by the battery owner and operator. Most of today's revenue opportunities are designed to efficiently optimise bulk energy supply and do not fully recognise the value of storage.

In this section, we assess the market, financial, commercial and policy framework surrounding development of utility scale battery projects and identify the key enablers and barriers to investment from the private sector.

These drivers are solely based on the revenue assessment for batteries that has been undertaken as a part of this study and do not necessarily include broader considerations within the battery domain, including emerging alternative storage technologies, supply chain dynamics, dramatic cost reductions in battery projects with ongoing research and development, which might equally play an important role in incentivising investment in batteries.

18 EMCa for ERA – Report on the benchmark costs of ancillary services in different jurisdictions- February 2020

Uncertainty in forecasting revenues creates financing challenges for battery projects

Price volatility is an essential feature for battery profitability, as evidenced within the modelled results. However, as wholesale energy and ESS price spikes are challenging to predict, it is not possible to include the full revenue from price spike events in financiers' project cash flow projections, reducing the bankability of projects. Often storage projects are exposed to either higher interest payments or limited debt funding (due to high debt service coverage ratios i.e., 2 – 3 x operating income) increasing the level of investor risk not commensurable to the return.

Key bankability challenges associated with both energy arbitrage and ESS revenue streams include:

- Large spikes in wholesale energy prices can produce material cash flows for energy storage projects, provided they are optimised to discharge during such periods. However, as wholesale energy price spikes are challenging to predict, combining this with a typical 'time of day' trading strategy may result in conflicting priorities. As a result of this unpredictability, it is not possible to include the full revenue from price spike events in financiers' project cash flow projections. As a result, financing for a battery storage system requires a portfolio of bilateral contracts, including a floating to fixed premium.
- Essential system security services can require the storage project to charge or discharge, creating the possibility of the system operating out of sync with trading strategies.
- The use of storage projects for ancillary support needs to be considered in the maintenance and operability of the hardware. Overuse of storage projects could lead to increased erosion of performance and the need for additional maintenance.
- The impact of imperfect foresight associated with uncertainty in forecasting is particularly relevant for batteries since it determines the value of energy in storage – both when choosing to supply and when choosing to store. The simplification of perfect foresight is becoming material in planning for most electricity markets and leading to conclusions which underplay the need for storage – particularly long duration storage. With imperfect foresight, shorter storages lose a significant proportion of their theoretical (perfect foresight) value. This is then compounded by issues of deciding between price certainty in the moment versus the potential for higher - but more uncertain - returns later for battery operators in real time, based on uncertain pre-dispatch forecasts. While the WEM's RCM is intended to partially offset financing challenges by providing revenue certainty through capacity credits, it is currently undergoing further review to ensure any bankability challenges do not emerge for battery energy storage projects.[19] Steepening the capacity demand curves results in potentially significant changes in capacity prices, which can contribute to investment uncertainty. This is especially the case for batteries that are investing in long duration storage (e.g., 4-8 hours). To invest in long-life, long-lead-time assets, there needs to be clear and reliable revenue opportunities to produce a strong business case for investment. Many of the lowest-cost prospective battery projects have long lead times, meaning that these business decisions must be made 5-7 years before they enter the market.[20] These factors make it difficult to finance projects, even where a clear need for development exists.

Revenue sufficiency under the existing real time market arrangements is not adequate to compensate for positive externalities created by batteries

Significant and regular energy market price spreads can provide a basis for investment in high duration storage (e.g., pumped hydro). Additionally, in the WEM, it is important to ensure price caps in the WEM do not restrict the recovery of cost for resources.

Given the current projected price spreads, additional payments from the capacity market would be required to make energy storage viable. This is further evident in other jurisdictions which have energy-only markets including NEM where batteries derive large portions of arbitrage revenue from extremes of pricing (either positive or negative), with majority of income during all quarters came from intervals where prices are above AUD $300/ MWh. This kind of price band analysis has important ramifications for how battery revenue is

[19] WA Government – Reserve Capacity Mechanism Working Group

[20] PWC – Energy Storage: financing speed bumps and opportunities – February 2019

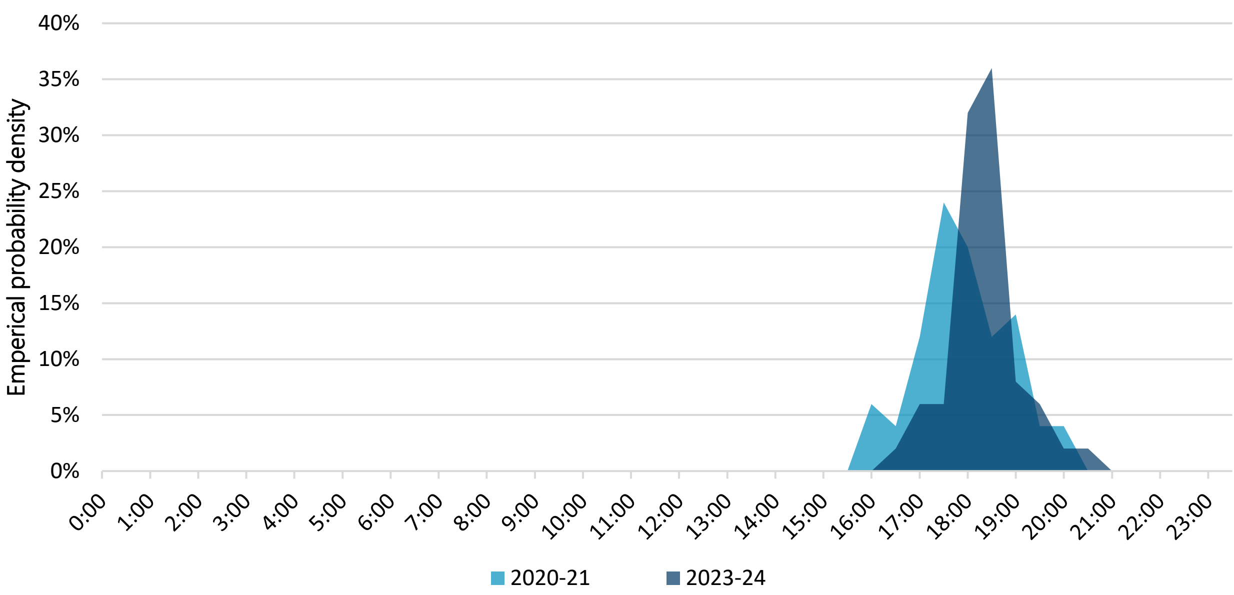
forecast, particularly in the context of bilateral capacity contract valuations as well.

As shown in Figure 17, within AEMO's WEM 2021 ESOO demand simulations, the peak demand is forecasted to continue to occur during summer and is expected to shift 30 minutes later. This is due to the combined impacts of behind-the-meter PV generation and battery storage operation, and, to a lesser extent, convenience charging of EVs. Additionally, depending upon the level of electrification, high-capacity stress events due to an increased level of intermittent generation and projected economic growth, the peak demand is expected to last longer i.e., 6 hours relative to 4 hours. Currently, AEMO has determined that the capacity obligation window for storage facilities is only 4 hours. For a 100 MW / 400 MWh facility, this would mean offering 100 MW in every hour for the four-hour ESR Obligation Duration. However, as peak demand shifts or lasts longer, AEMO could extend the ESR Obligation Duration and/or the Duration window to avoid creating new peaks in demand as shown in Figure 17. This implies that a 100 MW battery will have to increase storage by 50 MWh to ensure that it continues to be accredited for 100 MW of Capacity Credits if the peak demand was to last longer than 4 hours. Note that this is dependent on the generation mix.

This implies that regular reviews of the effectiveness of the certification of Reserve Capacity will need to be conducted, ensuring it is consistent with the likely future changes in Operational Demand in the SWIS. For example, if the dispatch window does not coincide with peak Balancing Prices, then the pricing of capacity credits might need to account for this possible decrease in energy and ESS profits. If AEMO forecasts that the dispatch window will increase to 8 hours, but remains at 4 hours, the investor for 8-hour battery will need to be adequately compensated for additional capacity revenue.

Additionally, as observed in other jurisdictions, the specifications of units to receive a certain amount of capacity credits influences the investment outcomes considerably.

Figure 17: Distribution of forecast time of 10% POE peak demand, expected demand growth scenario



Source: 2021 WEM ESOO Data Register – AEMO

As shown by the modelling results, battery storage's dominant source of revenue stems from ESS markets, given the low opportunity cost for degradation associated with cycling. However, the volume of services required to meet the ESS requirements is relatively shallow, depending upon how the market evolves, and profitability could be eroded quickly with increased competition from other ESS resources.

ESS markets are inherently designed around the concept that ESS services are provided as additional services required by the power system: services that are in addition to the primary mission of supplying energy. ESS service prices reflect the opportunity costs generators incur when they withhold capacity from the energy market to supply ESS services.[21] Ancillary service market prices are set by the highest cost unit selected, the unit with the highest opportunity cost in the given trading interval. A co-optimised dispatch engine recognises the importance of opportunity costs and automatically includes each generator's opportunity cost in the co-optimization algorithms that simultaneously clear energy and ancillary service markets at the lowest cost possible. The generators do not have to include their opportunity costs in their bids; the dispatch engine for the market does that for them automatically. Generators then maximize their profits by bidding in near zero costs for supplying ancillary services and accepting the price that the ancillary service market clears.

The market situation for batteries is different than for traditional generation. Given that the majority of the battery revenue stems from ESS services and battery operators tend to incentivise participation within ESS markets to preserve cycling costs, maximising availability payments, energy market-based opportunity costs tend to be quite low. As a result, if there is enough of this energy storage to completely supply the specific ESS services needed, the market price collapses to zero. With little supplementary energy market income to cover capital costs, the battery is not economically viable, even if their total costs are less than the traditional generators' marginal opportunity costs. Experience from the UK indicates a rise in battery participation leads to a decline in ancillary service (i.e., FCAS) prices, with its firm frequency response quarterly average dynamic price dropping from 20 £/MW/hour in Dec 2016 to nearly 10 £/MW/hour in Dec 2019 i.e., a 50% reduction.[22] Within this period, batteries have displaced both gas and hydro assets nearly doubling in capacity.

Batteries will result in several financial and technical benefits to the surrounding network area, including reduced risk of curtailment and alleviating pressure on network infrastructure. This is recognised under the proposals for non-co-optimised ESS.[23] Despite these broader benefits, there is currently no ability for one project to 'charge' another project for the benefits provided to them. This 'charge' could be solicited through a regulated return, like the structure in place for shared energy infrastructure. Alternatively, energy storage could be added to the portfolio of traditional transmission solutions when the driver for the investment is relieving transmission congestion. Markets centred around congestion relief are likely to incentivise batteries to be operated to mimic the effects of those traditional solutions (such as transmission construction and line re-conductoring) to alleviate congestion.

Commercial viability of battery projects requires further development of market structures and incentive mechanisms to recognise and value the services batteries can provide, including for Fast Frequency Response ("**FFR**"), transmission congestion relief and simulated inertia.

Large-scale battery storage would be facilitated by reforms to the ancillary market, rewarding batteries for providing regulation services and their performance in the market. Novel approaches have been adopted across the UK, US, and Germany. The UK National Grid's Enhanced Frequency Response Tender sought suppliers to provide sub-second rapid response frequency reserves. Eight battery storage contracts were entered into for 4-year contracts with eight battery storage facilities for prices between GBP 7 and 11.97/MW/h. The tender to procure enhanced frequency response was oversubscribed 7 times the required capacity, with 1.2GW of battery capacity. In Germany, the grid operators and European Power Exchange have established a transparent market system for flexibility providers who would like to participate in the congestion management process.[24]

[21] Ancillary Services: Technical and Commercial Insights, Kirby.B – July 2007

[22] FTI Consulting Analysis

[23] https://www.wa.gov.au/government/publications/framework-non-cooptimised-essential-system-services

[24] KPMG – EFR tender results – September 2016

In contrast, the US Government directed that frequency regulation services were to be compensated based on performance. Consequently, the PJM interconnection created two different signals, a conventional signal and a fast signal, to give more responsive technologies the advantage over conventional technology. The US's Midcontinent Independent System Operator's ramping product is procured on a mixture of day-ahead and real-time bases.[25] All dispatchable resources in the territory can participate. Resources providing the ramping services are compensated for the opportunity cost, based on the other products in the market.

The US's approach is likely to be the most successful in Australia, as it compensates for the opportunity cost, which has been a concern for battery owners in Australia. Additionally, a performance-based reward system for ancillary services would benefit the fast-dispatch technology offered by batteries.

Key innovations to consider in capacity markets, such as WEM for a renewable energy-based, flexible system with adequate battery penetration

The role of capacity markets has traditionally been to incentivise investments in new generation capacity when capacity is needed. With the increasing penetration of variable renewable energy **("VRE"),** an efficient means to increase flexibility in power systems is to introduce flexible resource requirements into the existing capacity mechanisms that could incentivise investments in more flexible resources, meaning resources that can ramp up and down quickly.

[25] National Renewable Energy Laboratory – Providing ramping service with wind to enhance power system operational flexibility – 2019

Innovation considerations	Potential issues that can be addressed
Valuing available flexibility that can be provided by batteries in balancing markets through elements of scarcity pricing	Ramping flexibility (MW/min) needs seem to be higher during high renewable generation and demand conditions, while all types of flexibility needs are generally lower during low renewable generation and demand conditions. However, the relationship between required flexibility needs and expected system conditions is difficult to capture with simple statistics and may require the employment of more advanced techniques. Capturing the 'dynamics' of flexibility needs in advance can help to better manage the available flexibility means. Our modelling results demonstrate that batteries contribute substantially to covering the flexibility needs. Of course, this will only be the case if these flexible technologies, which are assumed to be available in real time, are effectively installed and participating in the balancing market. This contribution of decentralized capacity is explained by their cost structure, which allows a reduction in 'must run' or reservation costs. Facilitating the further development of these flexibility providers and valuing their flexibility will further increase the coverage of flexibility needs, contributing to a cost-efficient integration of renewable energy. This can be resolved by a well-functioning intra-day and balancing market, complemented by reserve capacity being contracted by AEMO through the RCM to cover the residual flexibility needs which remain without coverage by the market. Scarcity pricing may be required in the long term to ensure reliability standards are satisfied with high levels of intermittent capacity and limited energy resources, provided appropriate market power mitigation measures are in place.
Incorporation of locational marginal pricing within existing RCM	Locational Marginal Pricing would provide batteries with more granular information regarding concentrations of generation, load, constraints in the network and volatile prices. This provides clearer price signals, increasing investment in points in the grid where demand is underserviced. Shadow locational pricing suggests that high price variation nodes will exhibit more persistent price variation signals than the regional reference node. Therefore, despite increased complexity, full-nodal pricing would increase the number of price points, allowing private investors to place batteries in locations with high unserved demand. This would likely lead to better ancillary service markets and increase the ability to engage in arbitrage trading. This may be beneficial for battery storage systems in the longer run, but it may delay the exit of higher cost generation where this benefits from network congestion rents. Locational pricing also means that any benefits from a battery storage system reducing network congestion cannot be monetised unless specific congestion relief markets are created to extract this value.

Innovation considerations	Potential issues that can be addressed
Differential Capacity Prices based on the costs and duration of providing flexible generation and storage	Current capacity prices are set with reference to OCGT Fixed Frame Units.[26] This may not provide revenue incentives for the entry of flexible generation and storage facilities that are required to maintain supply reliability at an efficient cost. In addition, the variability in the current RCP due to the application of the convex capacity price curve makes the price highly sensitive to changes in excess capacity. This will affect how long-term investments in flexible generation and storage facilities are evaluated.
Long term capacity contracts based on a technology based net cost of new entry (CONE)	To encourage the transition to a flexible generation and storage fleet in the WEM, provide long term capacity contracts for new entrant generation and storage facilities at the minimum of their offer price, with escalation included. This will ensure that new entrant capacity providers can lock in (at least) 10 years of capacity prices if required to facilitate investment in dispatchable generation. Additionally, a technology-based capacity price based on setting the net cost of new entry **(“CONE”)** could be offered to longer type contracts. Investors need to be able to secure long term capacity prices that cover a substantial portion of gross CONE (annualised capital and fixed O&M costs), with the balance provided by energy and ESS markets (and LGCs for renewable generation). Offering 15-year contract lengths provides significant benefits to the market, including securing a lower cost of capital that helps reduce the cost of securing required capacity in the WEM and helps reduce market concentration in the WEM.

Aligned policy, regulatory and commercial incentives can help reduce levelised cost of supply for batteries

Capturing the massive economic opportunity underlying the shift to battery-based energy systems requires a “whole of system” approach across policy makers, regulators, and investors. The increasing and divergent mobility and grid-tied storage applications that emerging battery technologies can address hold incredible potential to reduce carbon and other polluting emissions while unlocking enormous new sources of economic value.

As cost and performance improvements continue to outpace analyst forecasts, investors, vehicle original equipment manufacturers (“**OEM**s”), and other value chain players are racing to meet expected Li-ion battery demand while competitively pursuing incremental and step-change improvements that can reduce costs or open up entirely new end-use markets. Similarly, incentivising battery manufacturing and critical mineral (lithium, cobalt etc.) exploration to reduce national security risks of relying on foreign suppliers will be key to ensuring that costs for battery energy storage systems do not increase significantly due to supply

[26] Economic Regulation Authority – Benchmark Reserve Capacity Price, November 2020. https://www.erawa.com.au/electricity/wholesale-electricity-market/market-procedures

chain pressures as witnessed in recent times.

Supporting this type of innovation and energy system transformation, however, requires an ecosystem approach that combines and aligns these private and public sector commitments as shown in Figure 18.

Figure 18: Ecosystem approach diagram

Policy incentives

1. Strategic tax incentives.
2. Adopting an ‘energy security target’ to send a market signal to investors that storage technology is a worthwhile investment, reducing uncertainty brought by changing policies.
3. Adopt a ‘clean peak standard’ to promote investment in energy storage, especially those connected to wind and solar farms.

Look beyond Li-Ion for competitive grid storage

1. Alternative technologies to Li-Ion (zinc and flow batteries) are already competitive from a levelised cost of storage perspective to Li-Ion batteries for a range of applications including long duration storage. Early investors should capture a first mover advantage through various grants (ex. ARENA) that can commercialise the technology.

Whole of system approach

Alternative business models

1. Help investors demonstrate bankability through development of alternative financing model. Public private partnership, energy as a service, aggregators or ownership of energy storage batteries by NSPs including development of unregulated revenues are alternative pathways that can reduce financing costs. To facilitate ownership options, regulatory reforms will be needed.

Regulatory reform

1. Develop Pathways to integrate storage at different levels of grid operation and control. Recent examples include the new "integrated resource provider classification" ruled by AEMC that benefits storage to be co-located with renewable energy facilities for the purposes of avoiding curtailment while providing access to existing revenue streams within market.
2. Consider the impact of network demand charges bi-directionally which has historically disadvantaged storage providers in other markets including the NEM.

Source: U.S. Department of Energy – 2020 Grid Energy Storage Technology Cost and Performance Assessment

Market power will need to be carefully measured and managed for batteries

The modelling indicates that a battery storage system may operate as a pivotal or marginal supplier in RTMs, especially during minimum and maximum demand periods. Importantly, battery storage may also be the marginal demand, including during very low and negative RTM price periods.

There are various abilities of the merchant storage owner to exercise unilateral market power. Those include demand withholding, generation withholding and under-use, which results in increased congestion in both space and time when compared to the welfare-maximising use of batteries. Factors such as uncertain bids by other players, final state-of-charge requirements and arbitrage by other storage players can also impact profitability.[27]

This creates opportunities for a battery storage system to exercise market power and set prices both above and below those that would be expected if the battery storage system were not the pivotal supplier or pivotal demand. It is also possible for an early mover battery storage system to strategically constrain increases in its capacity over time so that it deters entry by other battery storage system operators and limits the quantity of total battery storage system capacity in the WEM to avoid a decrease in future demand and revenue.

This could result in opportunities for early mover battery storage systems to extract super-normal profits from other market participants up to the point where barriers to entry from potential competitors can be overcome. Such outcomes would not be consistent with the WEM objectives.

Battery storage short-run marginal cost (SRMC) is complex to estimate

The current WEM includes a range of design elements intended to mitigate the potential for participants to exercise market power.

Participants are not allowed to make:[28]

- STEM submissions with prices 'that do not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity when such behaviour relates to market power.
- Balancing Submissions with prices that exceed 'the Market Participant's reasonable expectation of the short run marginal cost of generating the relevant electricity … when such behaviour relates to market power
- LFAS Submissions with prices 'in excess of the Market Participant's reasonable expectation of the incremental change in short run marginal cost when such behaviour relates to market power.

These requirements are intended to ensure that, when participants have market power, their offers reflect SRMC. This metric is used with the assumption that participants recover fixed costs through the capacity mechanism.

However, estimating SRMC for batteries is complex given it is energy limited, consists of opportunity costs as a considerable component and the direct operational costs including charging costs are dynamic in nature, dependent upon market conditions, including initial state of charge. Additionally, the RTM price caps have been set with reference to the SRMC for thermal generation and may not be appropriate for periods when battery storage systems are pivotal suppliers.

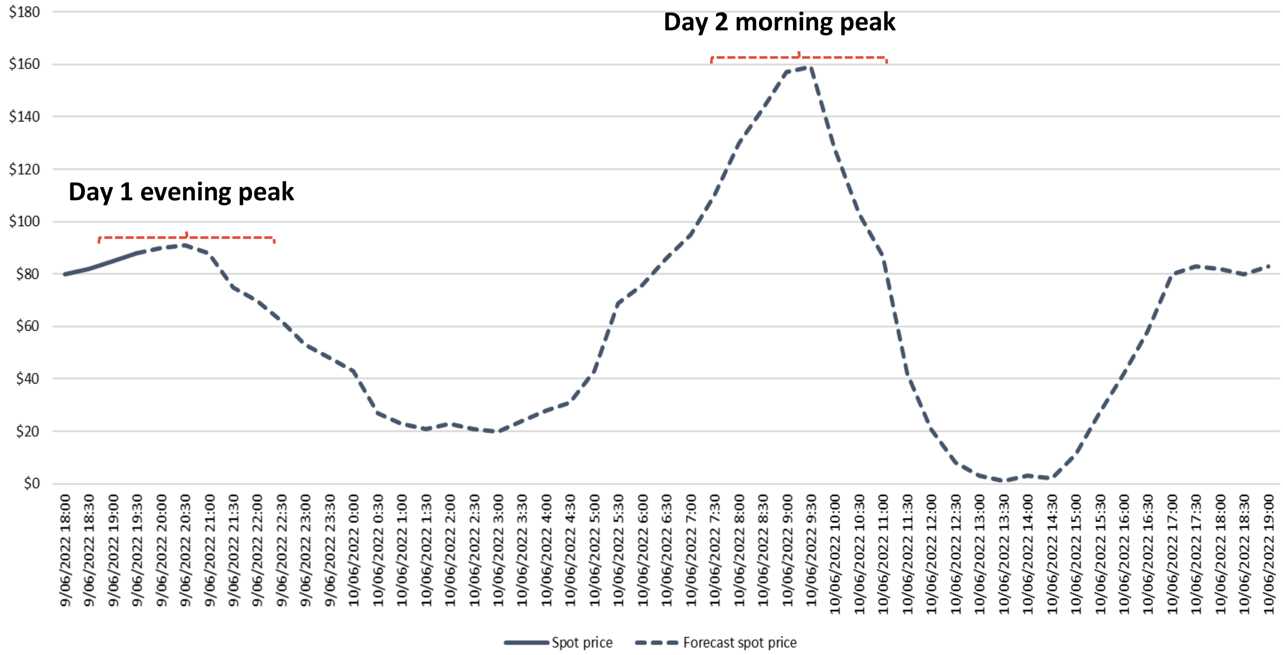
Our analysis shows that the price spread required to justify energy arbitrage needs to exceed the cost of cycling and efficiency losses. We estimate this to be around $50/MWh, which influences SRMC. However, the above price spread does not necessarily capture the opportunity cost associated with storing the energy for a time where it has higher economic value. Considering the number of investment barriers identified previously, allowing battery storage system operators to take opportunity cost into account in determining SRMC would encourage more battery storage investment.

[27] Applied Energy – Optimal offer-bid strategy of an energy storage portfolio: A linear quasi-relaxation approach – 2019

[28] Energy Policy WA – Directions Report – Clarifying Short Run Marginal Cost and market offer requirements in the Wholesale Electricity Market – 28th October 2020

For example, in the energy prices shown in Figure 19, a battery would be justified in offering its generation into the evening peak of Day 1 at ~$160/MWh because the battery could instead hold its charge and offer into the elevated morning prices of Day 2. If doing so means that the battery gets dispatched in the evening peak of 9/06 and sets prices at $160 (i.e., has market power / is pivotal), this is not an indication of using market power to manipulate prices. But this reflects the opportunity cost using the stored energy for energy dispatch, which is the best value the battery operator would be able to receive from using the stored energy.

Figure 19: Illustrative price example for battery dispatch



Taking opportunity cost into account could likely minimise the long-term cost of electricity supplied to customers and could incentivise battery storage investment because it increases potential revenues. However, this will require further investigation. That said, the adoption of an opportunity cost standard raises a number of complex conceptual and computational issues that should not be underestimated. Opportunity cost can be both very high and volatile. Typically, the opportunity costs of foregone generation will exceed SRMC estimates that are only based on direct operating costs.

Review of global market practices

Our short review of market practices in Ontario, Alberta, the US and New Zealand suggests that for energy limited assets such as batteries:

- The approaches taken to translate opportunity costs into practical guidelines for measurement of market power exploitation tended to focus on objectives related to practicality and transparency, as opposed to conceptually "correct" SRMC approaches based on simple direct cost calculation. Arguably, this leads, in a number of cases, to opportunity cost estimates at the low end of what these costs are likely to be;
- The opportunity cost concepts that are applied tend to differ according to the type of generation technology used in the specific context, so it seems that only markets with significant energy limited assets penetration, such as pumped hydro, have adopted an explicit opportunity cost approach for foregone future generation opportunities;
- Other opportunity cost components relate to a wide range of fixed and variable costs including any site overheads, wear and tear costs associated with cycling; and
- Several markets, including PJM in the US, apply some mechanism to limit the exposure, such as a maximum per cent over and above direct costs.

We conclude from this review of market practices adopted internationally that market power guidelines need to have a detailed consideration of the scope of such calculations, including timeframe and facilities that are included or excluded particularly from a market power perspective. For instance, the compensation scheme in Ontario allows for a 3-month period for opportunity cost calculation and typically excludes run-of-river plants from claiming any opportunity costs. Flexibility is of essence to cater for a wide range of service providers. For instance, in the above example, if a run-of-river plants can establish the usage of water from an upstream storage, there is flexibility in the scheme for it to bid it's SRMC at opportunity costs; and concerns about very high opportunity costs, including exploitation of market power, and the corresponding effects on consumers could be addressed by carefully defining certain limits on compensation payments.

The current market power mitigation regime in the WEM is unlikely to be effective in constraining battery storage systems. This problem was recognised by the Taskforce in May 2021.[29] Among other things, the Taskforce sought to reduce the current reliance on ex-post investigations of market power and proposed that the present SRMC rules should be replaced with a requirement to make offers consistent with those that the participant would have made in the absence of market power. It also supported the introduction of a suite of market power mitigation measures including trading conduct obligations, an objective market power test and additional targeted record keeping and disclosure obligations for participants that met the objective market power test. The Taskforce also supported redesigning the current rules setting real time market price limits. Further work on the detailed design of the Taskforces decisions is currently underway but has not been disclosed publicly.

Challenges for barriers to entry for battery storage systems in the WEM

While barriers to entry for new generation and battery storage system are being reduced under WA government led reforms, they remain significant in the WEM and SWIS. These challenges include:

- The highly concentrated structure of the WEM and the limited number of counterparties that could enter long term contracts with a battery storage system operator sufficient to support the efficient

[29] https://www.wa.gov.au/system/files/2021-05/Information%20Paper%20%20Market%20Power%20Mitigation%20_0.pdf

financing of battery storage system assets, by providing the floating to fixed premium over uncertain RTM revenues.

- AEMO dispatch decisions constraining large and small-scale renewable generation output for system security reasons. The current lack of transparency around this makes it difficult to assess the value of implicit support being given to thermal generation to dispatch higher quantities during low demand periods to provide ESS. This may deter the entry of battery storage systems.
- The continuation of 30-minute trading intervals in the WEM, following the move by the NEM to five-minute trading intervals from October 2021. This favours thermal generation and is a deterrent to battery storage system investment because it reduces potential revenues.
- The retention of zonal pricing and the allocation of network congestion rents. This may be beneficial for battery storage systems in the longer run, but it may delay the exit of higher cost generation where this benefits from network congestion rents. Zonal pricing also means that any benefits from a battery storage system reducing network congestion cannot be monetised. Zonal pricing also creates higher uncertainty and risks around the revenue effects of transmission augmentation.
- The Network Access Quantities regime, which allocates capacity credits to existing generators, even where they would not be dispatched in RTMs ahead of new generators, including battery storage systems. The modelling indicates this may be less significant than first appears due to the limited potential revenue from the RCM.

Appendix A – Sample day (3/09/2024) in Energy Arbitrage Only mode

Figure 20: Energy and ESS prices for sample day (3/09/2024)

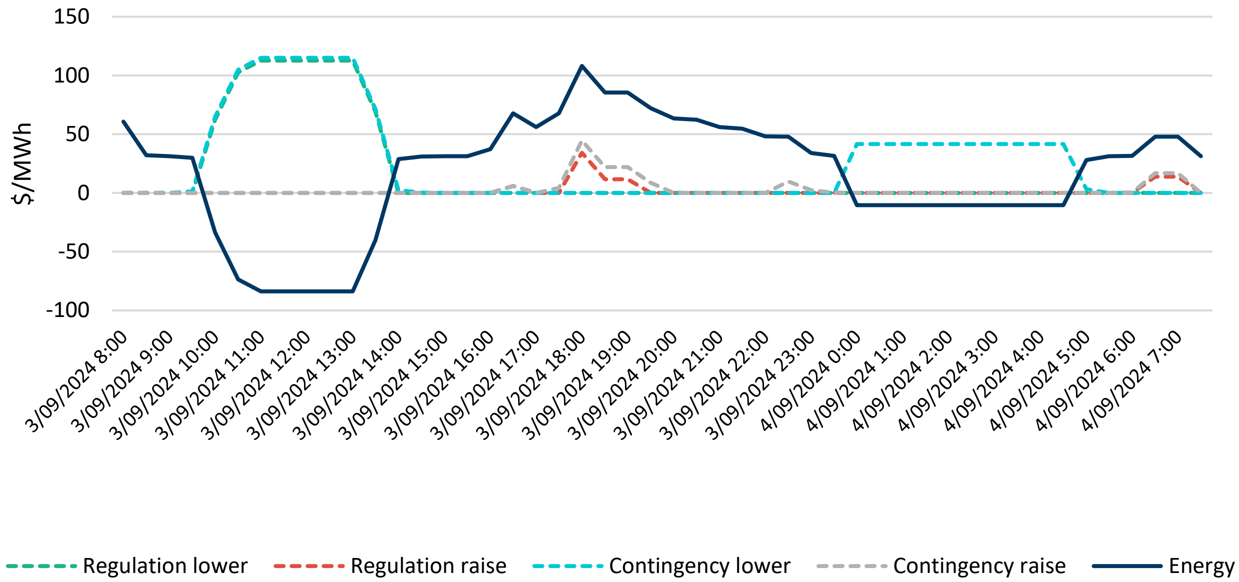


Figure 21: Battery storage system optimisation in Energy Arbitrage Only mode from B-ROM for sample day (3/09/2024)

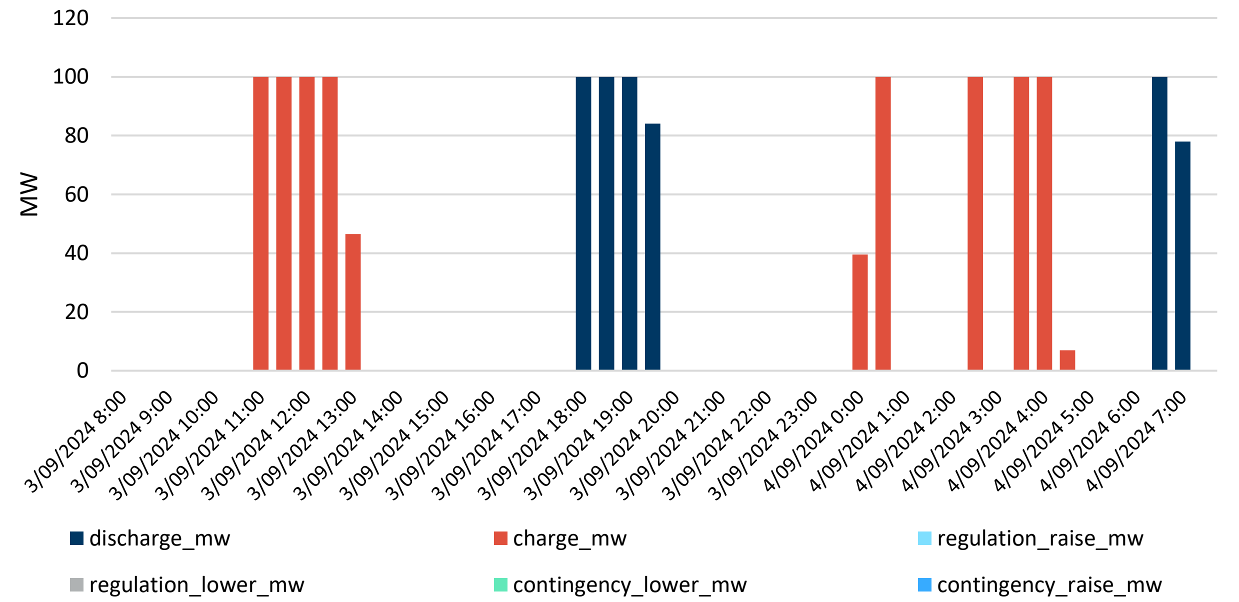
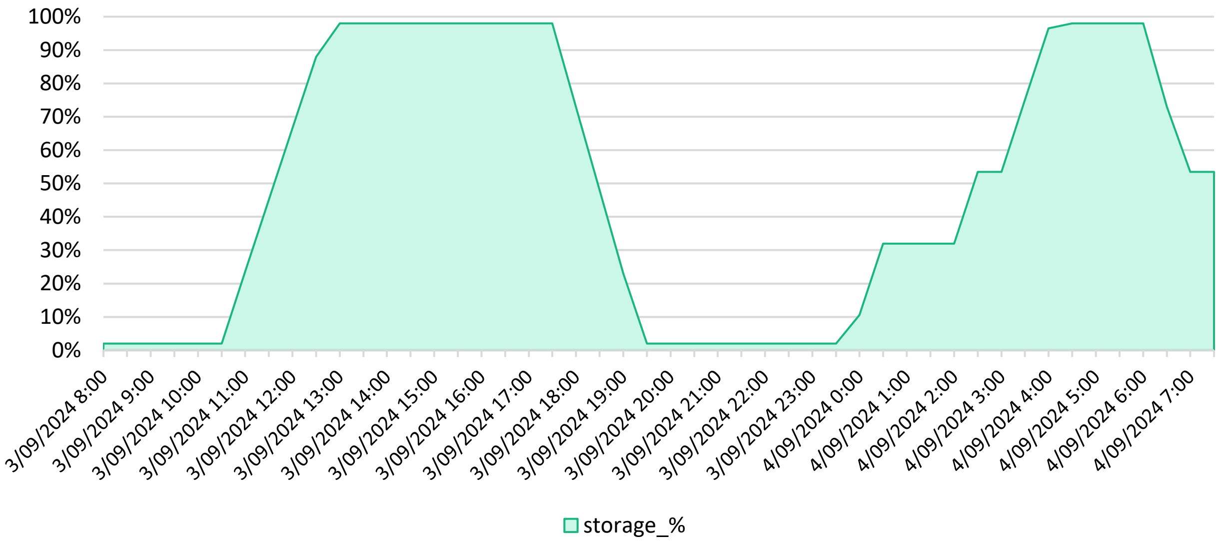


Figure 22: Battery storage system state of charge in Energy Arbitrage Only mode from B-ROM for sample day (3/09/2024)



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