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Investor confidence in Australia's National Electricity Market; energy storage systems and their barriers

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Abstract

Investment in energy storage has surged as the growing market share of variable renewable energy (in particular wind and solar PV) generation requires flexible firming capacity. In the last decade the confidence in storage technologies has grown. However, the investment landscape remains challenging. A survey of major investors in Australia's National Electricity Market has shown a keen interest in battery and pumped hydro projects, despite revenue uncertainty limiting market-led investments. The analysis in this article has outlined the revenue requirements for investment and established that revenue streams have supported short duration batteries but fall short as energy storage increases. Across a range of storage duration options, missing money shortfalls vary from $31-199/MWh for batteries, and $4-46/MWh for pumped hydro. Given the bi-directional nature of storage technologies, they are not well supported by generator-centric incentive schemes. While government schemes have been developed to address the missing money problem, they appear to favour revenue underwriting instead of addressing shortcomings of market design. This research introduces novel solutions that complement the capability of energy storage systems, building market efficient outcomes that increase consumer surplus.

Keywords: Energy storage; missing money; investment barriers.

JEL Codes: D47, D52, L94, Q40 and Q43.

1. Introduction

Energy storage as a technology class has been present in power systems for more than a century, originating in conventional hydro systems which were supplemented with pumping capability (Blakers et al., 2021). As the complexity of power systems grew, storage was often applied in systems where large inflexible generators (i.e. coal, nuclear) were allowed to maintain their operations at an optimal level without the need to adjust their output (Newbery et al., 2018). Storage would capture surplus energy when demand was low, then dispatch it again when demand increased (Ali et al., 2021; Newbery et al., 2018; Paine et al., 2014). This "firming" behaviour increased efficiency and flexibility and supported investment delays and deferral for new generating plant and power system infrastructure (Wilson & Hughes, 2014).

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The broader economic value of energy storage was recognised in the late 1990's, coinciding with the deregulation movement (Graves et al., 1999). With electricity prices reflecting the real-time cross section between supply and demand, generators available during periods of production scarcity were rewarded (Bidwell & Henney, 2004). Exploiting these price differentials provided a new opportunity for energy storage to "buy low and sell high" (Graves et al., 1999; Karaduman et al., 2023). Beyond energy arbitrage opportunities, other benefits arise from the operations of energy storage systems.

Technical operations improve through the provision of ancillary services (i.e. frequency and voltage control, power quality and system restart services), as well as providing additional reliable capacity to aid resource adequacy (Hartmann et al., 2019; Kirsch, 2011). Utilisation improves by deferring or avoiding transmission and distribution upgrades and supporting variable renewable energy through curtailment mitigation (Hartmann et al., 2019; Sioshansi et al., 2012; Wilson & Hughes, 2014). Consequently, consumer surplus improves with the total benefits exceeding the investment cost, making storage investment socially desirable (Karaduman et al., 2023). Despite the growing opportunities, uptake has been relatively slow with technical and market conditions making investment challenging (Tabari & Shaffer, 2020).

With growing acknowledgement of the impact of carbon emissions on the climate, interest in energy storage systems (ESS) has centred around their complementary technical capability to support variable renewable energy (VRE) (Ali et al., 2021). Despite the cost reductions of VRE over the last decade enabling their growing market share, large-scale investment in ESS has remained relatively slow. Early research by Sioshansi et al. (2012) and Wilson & Hughes (2014) explored the technical, cost, market, and regulatory barriers that impeded their uptake. A decade on from their work, this research seeks to explore the progress that has been made, and where challenges remain for this technology class.

Energy storage has operated in the Australian National Electricity Market (NEM) since the 1970's with Tumut 3 (1973), Shoalhaven (1977) and Wivenhoe (1984) pumped hydro energy storage systems (PHES) installed to provide support to the electricity network. Leading the global boom in large scale lithium-ion battery energy storage system (BESS), the NEM hosted the first grid scale battery storage system in 2018, aimed at addressing challenging frequency control conditions in South Australia. Since then, ~$3.4b[1] has been invested in short duration BESS, with 2.2GW/3.3GWh in service or commissioning across 29 projects (AEMO, 2024b). Two large scale pumped hydro projects are currently in construction, with Kidston PHES (0.25GW/2GWh) and Snowy 2.0 (2.2GW/350GWh) leveraging existing infrastructure[2] to expedite their projects and reduce overall capital costs.

The NEM provides an ideal environment to explore the challenges facing the roll out of ESS in modern electricity markets. Functioning as an energy-only market, participants are compensated for dispatched energy with a wide variance between the spot market cap and floor limits[3]. Commonly termed "energy arbitrage", the spot market revenue received is the difference between the cost of energy used to charge their storage, and the generation revenue from its re-dispatch. Determining the required price spread between charging and discharging needs to incorporate the internal system losses (contributing to its round-trip efficiency), short run marginal costs (e.g. charging costs), and long run marginal costs (e.g. scheduled maintenance, debt obligations, equity returns, etc). Similar to peaking generators, their dispatch may not

[1] All financial data contained within represents AUD
[2] Snowy 2.0 is utilising existing reservoirs within the Snowy scheme and Kidston is utilising former open-cut gold mine pits.
[3] As of FY2024-25, spot market prices can range from a floor of -A$1000/MWh to a cap of A$17,500/MWh.

always reflect these underlying costs, but more so the value they provide in scarcity conditions (Graves et al., 1999; Hogan, 2013; Karhinen & Huuki, 2019).

Technical barriers for ESS have largely revolved around the prohibitive nature of their capital and operating costs, low round-trip efficiency, short lifespan of chemical batteries (and their mid-life capital reinvestment requirements), uncertainty around their reliability and being unproven in large energy markets (Sioshansi et al., 2012; Wilson & Hughes, 2014). The drive to decarbonise global electricity systems has seen increased demand for storage to complement primary electricity production through VRE (Imannezhad et al., 2024; Srianandarajah et al., 2022). Established technologies, such as pumped hydro, have seen a resurgence in demand (Nikolaos et al., 2023), while lithium-ion batteries have emerged as a viable alternative. Cost reductions have been supported through the establishment of supply chains and the commercialisation of battery electric vehicles across the globe (Newbery et al., 2018). This has encouraged their broader application in electricity systems, enabling them to prove their capabilities in frequency and voltage control, flexibility in responding to market conditions (where they can rapidly change mode from charging to generating), operational reliability and round-trip efficiency. These factors have gone some of the way to alleviate technical barriers, however the non-technical challenges appear more stubborn to resolve.

Regulation and market structures have been slow to adapt to ESS opportunities. At its core, market designs have often limited the valuation and compensation available for the services that ESS can provide (Paine et al., 2014; Sioshansi et al., 2012; Wilson & Hughes, 2014). Beyond just energy arbitrage, small scale solutions (e.g. consumer and distribution level resources) can soften distribution network congestion, support power quality, provide voltage control, and leverage their cumulative scale through aggregation (Hartmann et al., 2019). By only compensating energy dispatch, the contribution that large scale systems can have in resource adequacy, deferring transmission investment, complementing VRE, alleviating minimum demand challenges and providing system services, leaves their real system benefits undervalued.

Despite the known barriers, network operators and rule makers approach change with caution (Gencer et al., 2020). For them, the risk of unintended consequences looms large. The complexity of power system operations is amplified by the increasingly distributed nature of network connections. Where BESS can essentially connect anywhere that has land available near existing substations, technical and operational challenges grow. Congestion, network stability and constraints can emerge through poorly sited connections leading to economic and functional inefficiency.

Where significant market led investment in short duration storage has occurred in the NEM since 2017, this research sets out to verify the barriers facing long duration projects and explore opportunities to overcome them. Building on prior research, a survey of investors has been used to gain contemporary perspectives on a range of technical, market, regulatory, and economic factors. Project developers, asset owners and operators, vertically integrated generator/retailers (gentailers) and financiers currently participating in the NEM have been canvassed to understand their confidence in the industry. Using their insights, the impact of these barriers will be quantified to inform policy makers of areas requiring attention. Based on the trends identified in the survey, revenue adequacy is assessed for a range of ESS technologies and durations. Using a detailed project finance model, the revenue requirements are established, and revenue sources are evaluated to determine whether market led investment is likely. Finally, two opportunities are explored to assist in stimulating investment in ESS and improving the coordination of their operations within the NEM.

This paper is organised as follows; Section 2 summarises relevant technical and operating challenges relating to ESS, Section 3 provides a review of relevant literature, Section 4 discusses the research approach, and Section 5 presents findings and explores novel solutions. Sections 6 and 7 provide policy considerations and concluding remarks.

2. Energy storage in modern power systems

Numerous studies have assessed the generation and firming requirements to support reliability and complement the uptake of VRE in the NEM (AEMO, 2024a; Blakers et al., 2017; Gilmore, Nelson, et al., 2023; Wood & Ha, 2021). The required energy stores (i.e. GWh), the nature of ESS installations (distributed, large scale, vehicle to grid), and their configuration (power to energy ratio) vary with each methodology. To decarbonise the NEM, estimated storage requirements range from ~15GW/125GWh (Gilmore, Nelson, et al., 2023), through to 56GW/660GWh (AEMO, 2024a). While technologies, durations and cumulative storage volumes change with each modelling exercise, the crucial role that storage plays in future power systems remains consistent. As a load, storage creates greater demand in periods of VRE oversupply, capturing energy that would be otherwise spilled. When generating, its flexible supply helps reduce the sticky reliance on emissions-intensive generation sources.

Where generation plant is characterised by their power output capacity (typically in megawatts), ESS are also described by their energy storage (in megawatt-hours). The relationship between the two, commonly termed duration, describes the time that they can operate at full power output before their energy stores are depleted. While their operation will likely never follow this simplified description (particularly for longer duration systems), it does provide some insight into their likely behaviour. For example, short duration storage (i.e. ~2 hours) will behave akin to a peaking generator, which are flexible and reactive, operating only during the highest price periods. As storage duration increases, behaviour typically changes with a broader scope to provide sustained output (operating through periods of volatility), defend contracts, or deliver strategic portfolio benefits to their organisation.

The simplified metrics that are typically used to distinguish between generating technologies are their capital cost, by power capacity ($/kW), and their estimated levelised cost of electricity (LCOE). This calculates their total lifecycle costs divided by their total expected output, discounted to present value (shown as $/kWh). Equivalent comparisons between ESS and other generating technologies cannot fairly occur using these metrics. The capital costs associated with ESS consists of the power generating equipment (e.g. inverters and generators) as well as their energy storage components (i.e. battery cells or dams).

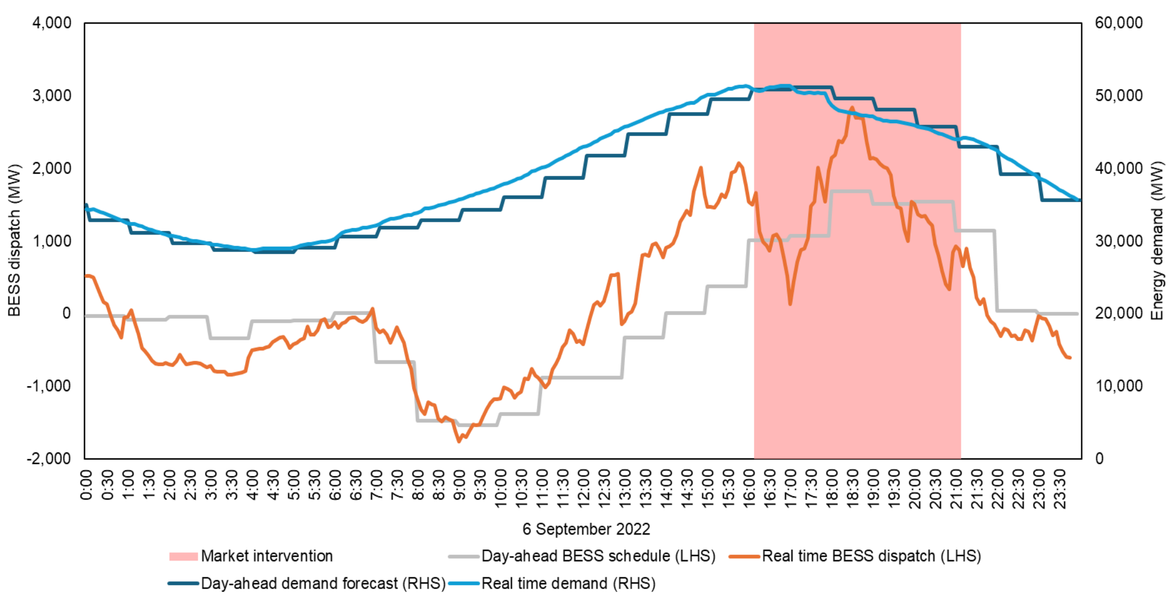
In an effort to overcome the challenges in comparison, Schmidt et al. (2019) expanded on the LCOE calculation to produce a levelised cost of storage (LCOS). Their approach incorporated the total lifetime costs of the asset (capital, operating and decommissioning costs, with the addition of costs associated with charging), over the total generation dispatched across its operations, and discounting to present value. This approach enables a better understanding of the breakeven revenues required for each kWh of energy dispatched from the ESS, however omits the effect that project financing has on revenue requirements. As with the LCOE, the LCOS has similar simplifying limitations, particularly where the metric will favour those systems that can dispatch their entire storage reserve within a nominal cycling period (typically a single day). Across these comparison tools, readers will notice the multiple uses of $/kWh for comparing LCOE, LCOS and capital costs for generation and ESS. Suffice to say, care is needed whenever any of these simplified comparative metrics are used.

2.1 Coordination and efficient dispatch

Despite the cumulative energy storage capacity that has been achieved through global investment in BESS in recent years, their contribution towards resource adequacy remains limited. Through challenging peak demand periods in heatwave conditions, the California independent system operator (CAISO) remarked that “battery resources providing resource adequacy do not have sufficient charge to provide their full resource adequacy capacity value for four consecutive hours across peak net load periods” (CAISO, 2023).

The Californian market provides generators with an annual capacity payment and locational marginal pricing for real time dispatch. Capacity payments aim to compensate for investment costs and are calculated based on the individual generator’s contribution to resource adequacy. Short run costs are covered in the real time dispatch market. Despite the investment level risks being covered through capacity payments, generators face no immediate downside for their absence during peak periods[4]. Opportunities in the real-time dispatch market will drive output decisions, particularly as prices approach the price cap ($1000/MWh in normal operations). For any participant, no greater revenues can be achieved by delaying dispatch if the cap is reached, so by design, the market incentivises all available energy to be dispatched.

This situation was brought into sharp focus for CAISO in September 2022, where BESS performance proved sub-optimal in the most crucial operating conditions. Consider first the day-ahead commitments in Figure 1. Hot weather was forecast, with demand expected to gradually increase across the day, peaking at ~51GW at 5pm. BESS was scheduled to charge their reserves from 7am-2pm, before discharging through the peak demand at highest output from 6pm-10pm. Despite demand conditions occurring broadly as expected, the dispatch market saw prices reaching the market cap at various locations across the state earlier than anticipated. This prompted the rapid dispatch of BESS stores well ahead of schedule. As demand continued to rise, BESS output decreased as their energy levels were depleted. This caused various operator interventions. Demand response mechanisms were initiated, minimum state of charge requirements were imposed on BESS, and the manual coordination of dispatch was required (CAISO, 2022a).



[4] Although this may affect their capacity payments for future periods

Figure 1 - BESS dispatch during CAISO heat wave – 6 September 2022 (Source: CAISO, 2022b)

With a much greater price spread in the NEM, it would be expected that it should be able to coordinate its dispatch more effectively. On the contrary, on the 27th of November 2024 BESS proponents in NSW were directed to maintain their state of charge during hot weather and high demand conditions. The Waratah BESS was required to reserve 96MWh of energy for out of market dispatch through the height of market volatility. Despite the very high range of spot market prices in the NEM's energy-only market, the market operator appeared uncomfortable that the resources would be efficiently coordinated. As power systems have historically been tested by peak demand, it is unsurprising that these situations are faced here first. Nonetheless, market structures are also proving unable to coordinate optimal charging of these important resources during minimum demand.

On the 19th of October 2024 in the South Australian region of the NEM, supply from distributed solar PV was greater than the state's energy needs, causing a sustained period of *negative* operational demand. Reliant heavily on the state's interconnectors to export surplus energy to neighbouring Victoria, the price signals to incentivise the charging of energy storage remained weak. Across the daylight hours, Figure 2 shows the cumulative behaviour of BESS through this period. The general trend shows ESS charging following wholesale prices (ρ = 0.4), however the magnitude of charging decreases considerably after minimum demand reaches its nadir. The relationship between price and demand is higher (ρ = 0.6), but remains quite stable, with only three short periods where prices dropped notably. Observations from this day highlight two things; 1. the lack of depth of the energy storage resources, and 2. the lack of variance in market prices through the deepest period of minimum demand to optimally coordinate the ESS.

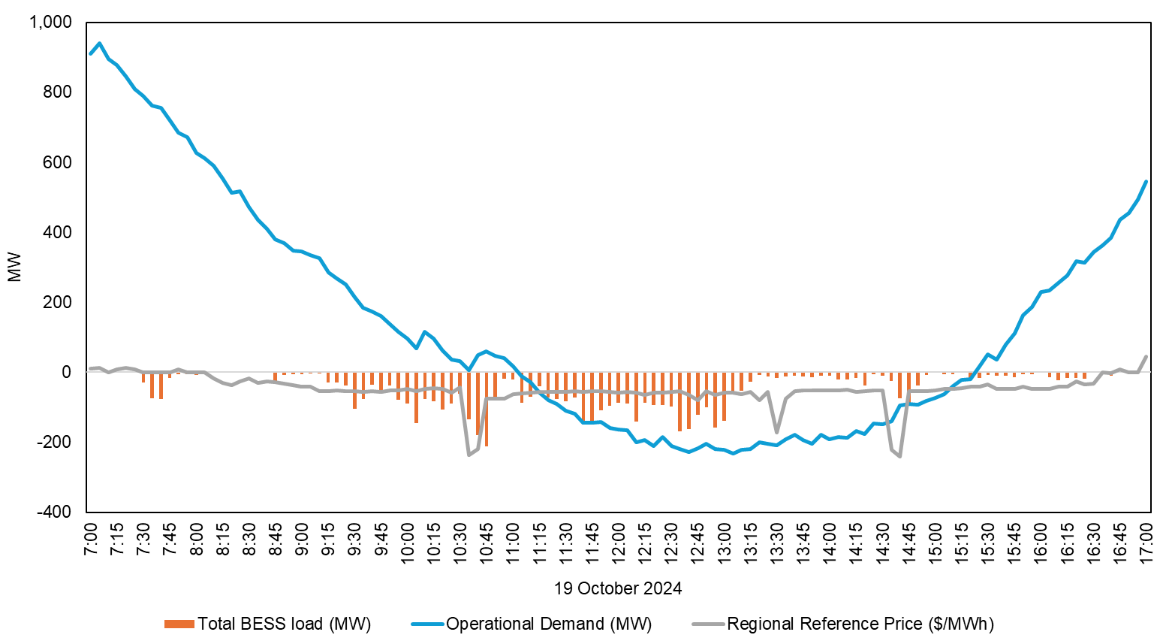


Figure 2 – BESS dispatch during South Australia negative demand – 19 October 2024

These examples provide an early indication of the challenges that are likely to continue as investment in short duration storage continues. If storage is expected to improve market efficiency and network stability, the need for greater coordination and greater depth in capacity is essential.

2.2 Sources of revenue

The established sources of revenue available for ESS investments in the NEM are summarised here.

2.2.1 Energy arbitrage

To maximise their profitability, ESS dispatch decisions must contend with continually varying input costs. These relate to their cost of charging, the need to overcome the cost of round-trip losses, and strategically managing their state of charge through the uncertainty of power system operations. Imperfect foresight faces all participants but applies especially to energy constrained suppliers (McConnell et al., 2015; Sioshansi et al., 2009). Imperfect foresight occurs when unforecast or rapidly changing market conditions lead to heightened price volatility that is not captured by participants. Where market led investment has primarily been in short duration BESS, the need for accurate forecasting and dispatch decisions is vital. While longer duration assets have greater opportunity to generate through periods of volatility, holding storage over multiple days reduces their exchange with the market and increases the price spread required to recover their long run costs. Importantly, missing peak prices will lead to sub-optimal returns for all investments.

With investment in storage growing in the NEM since 2017, NEM intra-day price spreads since this time are presented in Figure 3. This shows the average difference between minimum and maximum prices as duration increases. We see that the majority of intraday volatility occurs within 2-3 hours, after which revenues are quickly diluted. Compared to the 1 hour price spread, average revenue decreases by 27% at 2 hours, 49% at 4 hours and 67% at 8 hours. These diminishing returns are consistent with discussion in McConnell et al. (2015) and Paine et al. (2014). It is important to note that this ex-post summary does not account for the impression on pricing that additional ESS capacity would have (both generation and load).

In a perfect world, the limit of daily cycling for long duration storage to sustain a full state of charge nominally sits at 10.5 hour of discharging and 13.5 hours charging at 78% RTE. However, due to the limits of plant availability, maintenance and the lack of economic opportunities, the functional limit of daily cycling sits well below. McConnell et al. (2015) suggest that the marginal value of ESS above 6 hours is limited with respect to arbitrage opportunities but may be extended to 8h to overcome challenges in imperfect foresight. Figure 3 again confirms this where the value of arbitrage opportunities has grown steadily in recent years, but the marginal daily value remains shallow at longer durations.

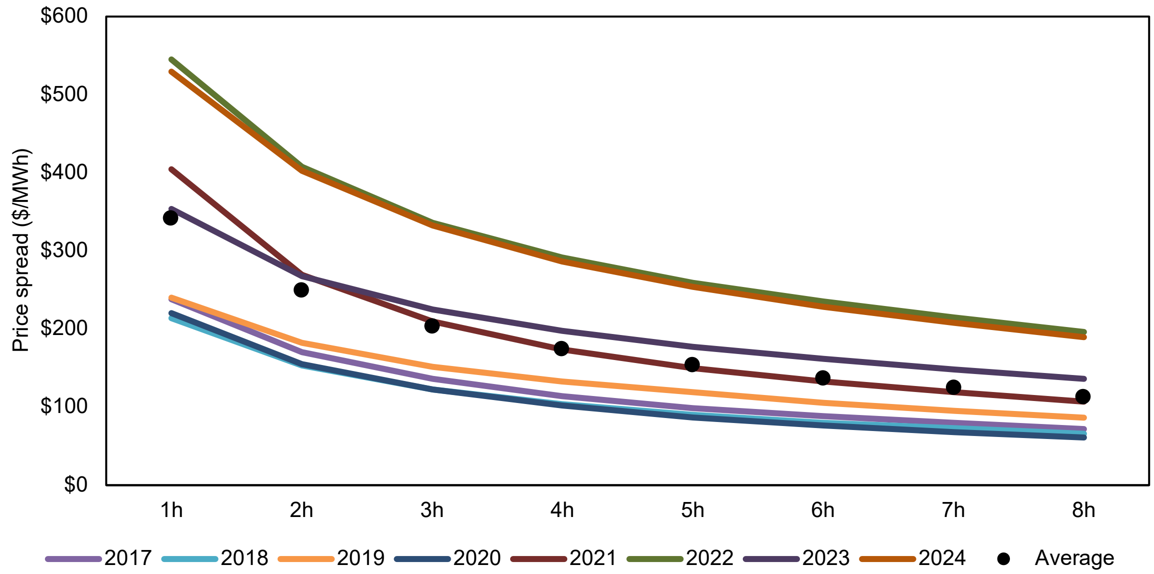


Figure 3 – NEM average intra-day price spread

In a high VRE market, it is inevitable that there will be periods where there is insufficient surplus energy to enable cost effective charging for short duration ESS[5]. With deeper energy stores, value exists in multiday trade and maintaining strategic reserves to defend contracted positions (or capitalise). This behaviour is analogous to peaking generators who extract most of their revenues through scarcity rents. Unpredictable timing and the low frequency of these events adds to the revenue uncertainty and missing money conundrum that faces peaking generators. Where long duration ESS carries uncapitalised energy over time, it holds insurance and social value that aligns with the network operators and policy makers objectives, but not profit motivated investors (Karaduman et al., 2023).

2.2.2 Frequency control ancillary services

In the NEM, frequency control ancillary services (FCAS) are dispatched competitively and co-optimised with real time energy dispatch. They operate to maintain the real-time supply/demand balance, with sufficient services allocated to resist the frequency deviation from the loss of the largest load or generator. Regulation 'raise and lower' services automatically increase/decrease power output to accommodate fluctuations within the normal operating band (50 Hz; +/-0.15Hz). Outside this, capacity is allocated through contingency services (both raise and lower) to respond on 1 second[6], 6 second, 60 seconds and 5-minute timeframes, to arrest larger frequency deviations. Being co-optimised with energy dispatch, there is a natural relationship between FCAS and energy prices. This can have a depressing effect when energy is plentiful, but exceptionally valuable during scarcity.

Summary information relating to the NEM FCAS markets are provided in Table 1. With increasing VRE uptake the magnitude of unanticipated ramping has risen requiring more FCAS. The proportion of FCAS enabled capacity to total generation capacity has remained quite consistent over time, averaging 16% of the total NEM installed capacity. With such a large

[5] Although Gilmore, et al. (2023) highlight occurrences where BESS have charged at $10,000/MWh to discharge later at $15,000/MWh, this comes with significant risk.
[6] Introduced in October 2023 which recognised the technical capability of BESS to respond in very short timeframes, allowing this capability to be compensated.

section of the generating fleet capable of providing these services and the market's co-optimisation with energy, the depth of the FCAS markets is very low ($\bar{x}$ 1.4% turnover). With growing BESS investment and the introduction of primary frequency response, saturation of these markets is becoming evident. Annual turnover across the FCAS markets was growing year on year from 2017 ($214m) to 2021 ($436m) but returning below 2017 levels by 2023 ($145m).

Table 1 – FCAS market summary; 2017-2024

2017-2024	Regulation		Contingency						FCAS total	NEM total
	Lower	Raise	Lower 6s	Lower 60s	Lower 5m	Raise 6s	Raise 60s	Raise 5min		
Average market revenue ($m p.a.)	$26.13	$49.96	$14.94	$15.81	$4.21	$79.30	$40.51	$19.82	$251	$18,075
Capacity (MW, 2023)	936	917	1,213	1,582	1025	2,301	2,361	1,766	12,101	84,033
Capacity change 2017 to 2024	+86%	+67%	+395%	+254%	+16%	+55%	+58%	-10%	+60%	+78%
Avg $/MW of enabled FCAS p.a.	$36,310	$61,232	$19,592	$14,393	$4,094	$41,649	$20,959	$11,049	-	-

(AER, 2024a, 2024b)

2.2.3 System services

Managing the power system within its technical operating limits requires a range of other processes that are not readily coordinated through markets. These are typically delivered through technical connection requirements or contracting between network operators and service providers when local or regional shortfalls occur.

The need for "system strength" services has emerged with the reduction in synchronous generation and increase in inverter-based systems[7]. Related to network voltage and its stability following disturbances, system strength has presented a significant challenge for network operators and generators alike. Processes to assess and manage minimum and efficient levels of system strength occur between AEMO and the regional transmission network service providers (TNSP). Through this process, minimum fault levels are defined at key transmission nodes. Generally measured in megavolt-amperes (MVA), minimum thresholds must be met to enable unconstrained operations. Through the connection process, the impact that new entrants have on their relevant system strength node are measured. Where negative effects are identified, they must be remediated[8]. Where services are procured through a TNSP, a system strength unit price is charged. This represents the long run average cost of providing an efficient quantity of system strength at that node over a ten-year period (AER, 2023). Across the 23 defined nodes in the NEM, over 74,000MVA of fault level is required to reach minimum levels, with an effective market value of $251 million per annum[9].

Although it has been suggested that BESS with grid forming inverters are capable of providing system strength services (Powerlink Queensland, 2021; Zhou et al., 2023), it appears that the preference of TNSP's is to contract synchronous machines for this capability (ElectraNet, 2021; Powerlink Queensland, 2024). Where PHES can operate as synchronous condensers, they can

[7] Asynchronous (e.g. wind) and non-synchronous (e.g. solar PV and BESS) are connected to the power system via an inverter. Despite AC generators being used in many modern wind turbines, the use of inverters and power electronics enables greater technical control and efficiency in their operation.
[8] This may occur by installing their own devices (e.g. synchronous condenser), contracting services from another private system strength provider, or contracting it through their TNSP.
[9] Excluding locational adjustments required for network impedance and other losses.

provide system strength services without depleting their storage reserves. When located effectively this can provide an added revenue stream.

Beyond system strength, other non-market ancillary services may be contracted for other technical issues. Across the analysis period, $327M in system restart services and $55M of network support and control services were procured. Given the discrete nature of these contracts, it is not considered a viable widespread revenue stream.

2.2.4 Contracts

Financial contracts are used to provide risk mitigation for the price uncertainty and volatility that exists in markets. These contracts take many forms but are generally designed to bilaterally manage opposing risks in the spot market. Despite the agreement, participation in the spot market is unavoidable. This means that the market risk is not extinguished but should be transferred to those that can best manage it (i.e. physically backed by generation assets). As a large portion of agreements are not centrally coordinated, there is limited reliable information on the turnover and value of these contracts. Flottmann et al. (2024) provides a good overview of the current contracting practices in the NEM.

ESS commonly engage in tolling contracts, collars, and caps, however energy constraints do limit their participation in the latter. Tolling contracts have been favoured for both BESS and PHES[10] projects as it reduces market risk and provides revenue certainty for investors. Collars provide a floor and ceiling on market prices, which can reduce risk for both parties. This type of arrangement has been used by the Federal Government through their capacity investment scheme to encourage efficient market operation, while investment risks are reduced through revenue underwriting. Cap contracts leverage the flexibility of ESS to turn on during high price periods, where they can offer a hedge for retailers and other consumers against market volatility. Typically set around a $300 strike price, when prices exceed this threshold the ESS revenues are capped and market revenues above are transferred to the buyer. In exchange, the ESS will receive a payment of a cap premium which provides a regular revenue stream regardless of market operations. Figure 4 shows the average daily close price of cap contracts traded on the ASX for the NEM, where the summer months (Q1) typically see the highest volatility and prices with peak demand.

[10] Notably the Kidston PHES, discussed earlier.

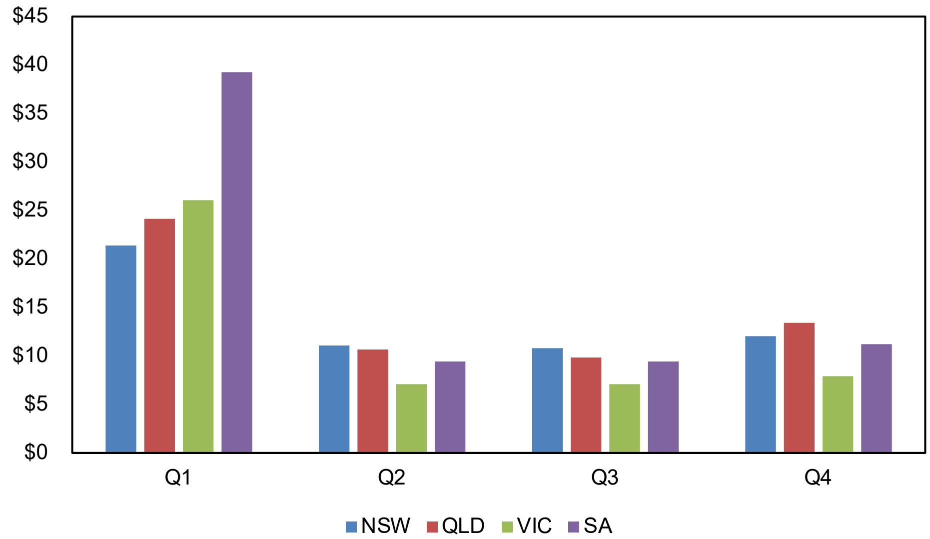


Figure 4 – Average quarterly cap contract price, ASX daily close (2017-2024)

3. Literature Review

This section will summarise the relevant literature relating to electricity market design and how investment in new capacity is encouraged. Two important articles that focus on the barriers facing investment in energy storage are identified and discussed. This will form the basis for later comparison.

3.1 Energy market frameworks and incentives for new capacity

Early development and growth of power generation capacity was designed to accommodate growing energy demands, primarily through government ownership in regulated systems. The efficiency that could be achieved through organised electricity markets was promoted by pioneering practitioners and scholars (Boiteux, 1949; Caramanis et al., 1982; Littlechild, 1988; Schweppe et al., 1988; Turvey, 1964), but relied on technological and policy advancements before the value could be realised. Advocacy for competitive markets and marginal pricing of electricity started to grow through the 1970s and 1980s across developed economies. Practical demonstrations highlighted the opportunities, such as software in 1980 that provided the marginal cost of load following plant and the loss of load probability across New York state (Bidwell & Henney, 2004). As various market structures started to form, they shared a focus on system sustainability that achieved reliable supply at the lowest cost (Gencer et al., 2020). The entry of private investment also reduced the capital burden from government as demand for electricity grew (Dyner & Larsen, 2001). The deregulation movement officially commenced in Chile in 1982, with many countries following in the decades since (Bidwell & Henney, 2004; Pollitt, 2004; Simshauser, 2018).

Deregulation occurred in Australia through the 1990s, with market derived pricing occurring within individual states and evolving as interconnection enabled trade across borders. The NEM itself commenced in 1998 (Rai & Nelson, 2020; Simshauser & Tiernan, 2019). Functioning as a real-time energy-only market, generators are dispatched to meet consumer demand in five-minute dispatch intervals. Formal futures markets operate on the Australian Stock Exchange, where a range of energy products can be procured ~three years in advance (Flottmann et al., 2024). This provides short term investment signals and offers hedging opportunities for both investors and load serving entities.

By developing economic incentives, electricity markets aim to do two things; 1. coordinate the generation resources in real time with consumer demand, and 2. provide investment signals for the expansion of capacity to replace and grow with demand. Various market designs have evolved, with most now functioning as either energy-only (with a megawatt-hour of electricity being the commodity traded), and combined capacity and energy markets (where payments occur for both installed power capacity and the dispatched megawatt-hour), with real-time, day-ahead and futures markets compensating participants.

Despite the best intentions, market imperfections have been evident since their inception and continue to evolve as changes occur in both supply and demand, and the broader policy context (Bidwell & Henney, 2004; Joskow, 2008; Newbery, 2016; Newbery et al., 2018; Simshauser, 2018, 2019) . To provide the needed signals for investment in new capacity, energy-only markets rely on sufficiently high and sustained spot prices to entice new entrants (Newbery, 2016). Though investors also see uncertainty, as high prices may be transitory, or subject to administrative caps upon commissioning their new capacity (Bidwell & Henney, 2004).

'Missing money' has been well discussed in the literature, which occurs when energy-only markets deliver sub-optimal returns for investors through administrative restrictions on market operations (Cramton & Stoft, 2005, 2006; Hogan, 2005; Joskow, 2019; Newbery, 2016; Simshauser, 2019, 2020). Price caps, market interventions and out-of-market mechanisms are often used to protect consumers and maintain market stability, but restrict the revenues of generators (Hogan, 2013; Joskow & Tirole, 2007). Peaking generators (e.g. open cycle gas turbines, long duration pumped hydro) are particularly susceptible to missing money, where they operate less frequently but rely on periods of scarcity to be compensated for their contribution to resource adequacy.

Administrative price controls in the NEM come in the form of the market price cap and an administered pricing mechanism that further restricts prices during sustained periods of scarcity. A cumulative price threshold monitors the rolling 7-day total of market prices, which triggers the administered price cap once the threshold is exceeded. If triggered, prices are capped at $300/MWh[11] until the rolling total returns to the normal range. In recent analysis, (Gilmore, Nelson, et al., 2023) show that storage and peaking generators experienced missing money in the order of 17-27% due to the constraints placed by the market price cap and administered pricing. Where these suppliers are necessary for maintaining system reliability, these administrative barriers can lead to early retirements (Joskow, 2019) or inadequate opportunities for new capacity (Newbery, 2016; Newbery et al., 2018).

In contrast to energy-only markets, some argue that markets with a capacity mechanism deliver new capacity more efficiently. Capacity markets function by estimating the capacity requirements to achieve set reliability standards, then compensation is allocated based on the certainty of a generator's supply (Cramton & Stoft, 2005). When the value of these payments exceeds the entry cost of new capacity, it should initiate a market response. This approach however lies very closely to the industry's origins in regulation, where risk is pushed away from investors and back to consumers. The presence of excess capacity is often be shielded from view of consumers in these situations as the market delivers stable prices, despite higher carrying costs (Gencer et al., 2020).

[11] A temporary increase of the APC to $600/MWh has been in place from December 2022 until June 2025, after which it is due to return to $300/MWh.

Although it has functioned well for more than 25 years, there are only few examples where the NEM has been able to incentivise large, capital-intensive merchant investments on its own (Simshauser & Gohdes, 2025). What has been favoured are peaking style generators with relatively short payback periods and capital requirements, namely gas turbines and short duration BESS. Government actions have brought significant investment in VRE (supported by the RET) by private investors, supplemented with direct government funding and ownership where necessary (e.g. Snowy 2.0, Kogan Creek).

3.2 Barriers to ESS investment

Early attention on the opportunities for energy storage systems in deregulated electricity markets arose in industry and academia in North America in late 2000s and early 2010s (Denholm et al., 2010; Paine et al., 2014; Sioshansi et al., 2009, 2012; Wilson & Hughes, 2014). The scale and sophistication of their power system and market operations allowed consideration of the role that pumped hydro and emerging battery technologies may have beyond just energy arbitrage. PHES investment in North America had broadly followed investment in nuclear between 1960-1980, with new interest growing in line with VRE deployment in the early 2010's (McPherson et al., 2018). Despite the potential benefits of storage being known, various technical and non-technical barriers have stood in the way of their widespread uptake (Simshauser & Gohdes, 2025).

Two key papers explored the range of factors affecting investment in energy storage. A summary of these will provide the basis for comparison later in section 5.1.3 of this research.

Sioshansi et al. (2012) set out their view of the possible applications for ESS, including energy arbitrage, generation capacity deferral, ancillary services, ramping, network capacity deferral, reducing renewable curtailment and end user applications (managing energy costs and power quality and service reliability). While observing that manufacturing costs, roundtrip efficiency and other technical characteristics are often cited as barriers for adoption, their focus went further to the non-technical limitations. While viewing the challenges from a North American perspective, they identify four categories which are broadly applicable to deregulated markets.

- Incomplete markets – lack of transparency and inefficiency in providing price signals for services, where markets have typically evolved with a focus on generation only.
- Valuation of storage services – where storage provides equivalent services to other power system infrastructure, they are unable to receive equivalent remuneration.
- Regulatory treatment of storage – the traditional approach to capacity expansion in regulated power systems disadvantaged new technologies. These persisted into deregulated markets, where the ability to leverage hybrid operations was limited.
- Investment risk and uncertainty – The combination of market and regulatory risk culminate in revenue uncertainty for developers and project financiers. With heightened investment risk, higher discount rates are typically applied in their financial analysis. This tends to reduce the commercial attractiveness (relevantly the net present value) of the storage project.

Wilson & Hughes (2014) followed, with a specific focus on the regulatory framework affecting storage developments (again in North America). They saw a role for storage in energy arbitrage, regulation and balancing, voltage support and grid upgrade deferral, but dived deeper into specific regulatory barriers. Further emphasising Sioshansi's work, they observe the difficulty in fairly valuing the grid services provided by storage, particularly where overlapping benefits are not acknowledged. Their research, and others Grünewald et al. (2012) suggested that it would be necessary for multiple services to be provided for investments to be profitable. However, they recognised that the aggregation of multiple services introduces new challenges, particularly where the simultaneous operation of one service may alter the ability to perform another. As a result, regulation and compensation of these services becomes complicated.

The regulatory treatment of storage, its classification, the development rules and mandatory requirements, access to revenues, and cost allocation formed several deterrents for investors. They found emerging trends within the market, where:

- Storage was not an approved provider – despite being capable of providing a service, market rules do not recognise it as a possible supplier.
- Investment was being deterred by technical requirements – where rules designed for existing technologies had not been adapted to facilitate emerging opportunities.
- Investment was being deterred by price structures – where there was no reward for providing services that are beneficial to the power system (i.e. incomplete markets).

4. Methodology

This research has three key components. An industry survey has been conducted to assess current industry sentiment on energy storage investments and contextualised against the literature in section 3.2. The trends identified through the survey will then be tested through project finance modelling of various ESS options, particularly focussed on the investment drivers considered by proponents. Finally, new market mechanisms will be assessed that complement the operation of the NEMs energy-only market design, targeting coordination and investment signals for ESS.

4.1 Survey

Participant selection focussed on organisations actively developing, operating and investing in power generation assets in the NEM. Several sources were assessed to identify suitable candidates, including generator information publications, rule change consultations and industry newsagencies which report on project developments. A generic survey link was provided to participants, which enabled their voluntary participation. No identifying information was collected, and data was aggregated as individual anonymous responses. The survey was available from August to October 2024 and the author is unaware of any substantial industry or regulatory announcements that would have influenced responses during this period. The survey was completed in accordance with Griffith University human ethics approval GU2024/614.

With the intent of assessing confidence in a range of key developments in the NEM, the survey explored current matters facing investors. The questionnaire consisted of four sections, relating to; 1. the respondents' role and their organisations current and intended participation in the NEM, 2. their interest in renewable energy zone development (covered in separate work), 3. the investment landscape for energy storage systems, and 4. allowed their views on policy and market opportunities. The survey used a mix of multiple choice, 5-point Likert scale, rank-order and short response questions.

The responses will be benchmarked against prior research then the impact of current barriers will be evaluated to identify where action is necessary. Insights are collected on investor focus, revenue streams, barriers, effect of government investment and synergies with other policy direction (i.e. renewable energy zone development). Perspectives from the different investor groups provides an important means of comparison. Specific to ESS, their development pipeline, technology preferences, storage duration, and how they are deploying ESS assets across their development portfolio can highlight the complexity of market-based investments.

4.2 Quantitative analysis

Building on the survey findings, a quantitative analysis has assessed whether there is sufficient revenue to support market-based investment in ESS in an energy-only market. To do this, a highly granular project finance model (PF model) has been used to calculate the minimum revenue required to satisfy finance conditions in the current market. The model is consistent with McDonald (2023), with minor adaptation to include ESS specific parameters[12]. The optimisation model works to minimise the long run marginal cost of asset operations, subject to achieving the investment hurdle rate, and constraints on gearing and debt serviceability. By satisfying these conditions, the minimum investment bounds can be defined. Investment scenarios considered the cost of stored energy across multiple time horizons, with BESS considered at 2, 4, 8 and 12 hour durations, and PHES at 8, 12 and 24 hours. Recent private investments in Australia have been limited to 2-4 hours for BESS and 8 hours for PHES.

With an understanding of current barriers and having defined the investment settings, options to overcome investment barriers are explored.

5. Analysis

5.1 Survey observations

At the time of developing the survey, the registered generating capacity in the NEM (excluding distributed energy resources) was 64GW (AEMO, 2024b). Invitations were sent to organisations actively investing in the NEM (through development, operations or financing projects in the NEM), with 33 complete responses received at a response rate of 42%. The demographics of respondent organisations are summarised in Figure 5, with first order investors (i.e. developers, generators and gentailers) estimated to represent 18GW of operating capacity. Within these groups, 42% of respondents filled executive level positions and a further 48% in management roles.

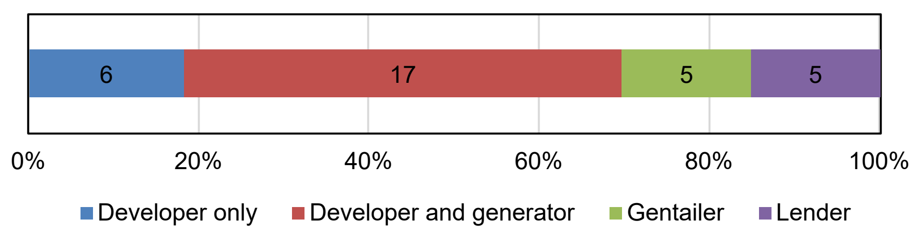


Figure 5 – Respondent categorisation

The investment focus for new ESS developments shown in Figure 6 is consistent with expectations, with nearly all respondents having an interest in lithium-ion BESS. The capital cost reductions and adaptability of this technology has supported its expansion across global markets and in the NEM. Respondents noted its increasing acceptance by network service providers and improving supply chains assisting with their delivery.

Pumped hydro remains popular despite the increasing competition from BESS. Respondents noted the challenges associated with approvals and social licence, and the revenue uncertainty for long duration storage. The remaining technologies have seen limited commercial application in large scale power systems, but some development opportunities are being explored. Hydrogen (as a storage system) showed greater interest from lenders than developers. This is

[12] Round trip efficiency and charging costs

likely due to the range of government schemes seeking to incentivise growth in the industry. Several responses noted their interest in the development of flow batteries but highlighted the commercial challenges associated with the technology.

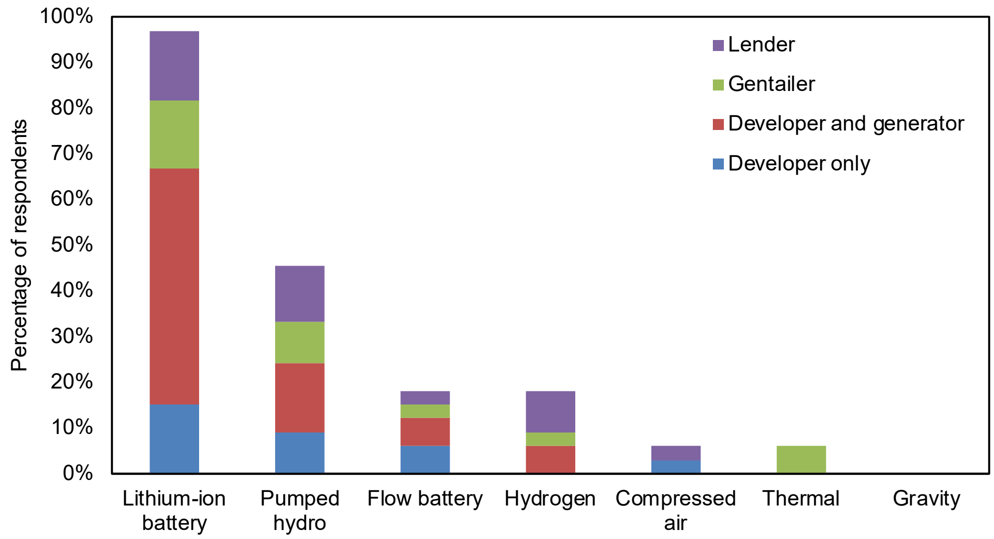


Figure 6 – Development focus for energy storage by technology

Recent market conditions have suited short duration ESS investments. Since the first large scale BESS was delivered in 2018, 1.6GW/2.2GWh of capacity has been added (average duration of 1.4 hours) and committed projects are due to add a further 3.7GW/7.7GWh (2.1 hours). Two pumped hydro projects are in construction which will add 2.45GW/352GWh to PHES capacity. Developments continue to focus on shorter duration projects, but are shifting towards ~4h duration, aligned with government investment schemes (Figure 7). Commentary provided by respondents for the 4-12 hours category highlighted that pumped hydro opportunities were being explored in this range.

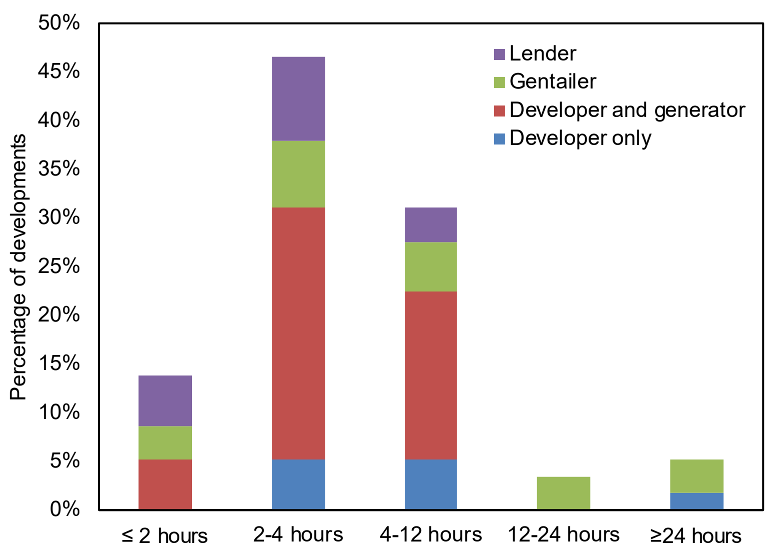


Figure 7 – Development focus for energy storage by duration

Modelling the transition of the power system towards decarbonisation shows a clear need for long duration storage in reducing the risk of energy shortfalls during VRE droughts (AEMO, 2024a; Blakers et al., 2017; Gilmore, Nelson, et al., 2023; Simshauser & Gilmore, 2024; Wood & Ha, 2021). When asked, respondents strongly pointed out the markets inadequacy in supporting long duration storage investments. The energy-only market design of the NEM will only compensate for energy that is dispatched. Above 4 hours, revenue uncertainty increases and calls for Government incentives were repeated. Insights into the deterministic policies[13] showed that the current tools aren't necessarily the best fit for large, complex projects with long lifespans. It was remarked that submissions for these schemes required a high level of conservatism, as there is no opportunity for review and adjustment as project developments progressed. The need for capital cost reductions and streamlining of the approval process were also referenced.

5.1.1 Sources of ESS revenue

The summary of established revenue streams suitable for ESS have been summarised in section 2.2. Figure 8 shows how they have been prioritised by respondents.

Frequency control ancillary service (FCAS) markets have been the primary source of revenue for BESS since their market entry. However, this trend has gradually changed from 56% FCAS/44% arbitrage in 2023, to 31% FCAS/69% arbitrage in 2024 (AEMO, 2025), consistent with relevant research (Gilmore, Nolan, et al., 2023). Survey responses align, placing the greatest importance on revenue derived from spot market arbitrage opportunities followed by FCAS. Respondents additionally noted that the unpredictable nature of market returns presents challenges to their financial planning.

The contract market offers a stable revenue stream that can reduce investor risk. Where swaps and caps are the most traded over-the-counter contracts, these are generally not well suited to short duration ESS. In the case of BESS, their tight energy constraints do not provide the required depth to defend cap positions during sustained periods of high prices. The function of the cap contract also reduces their capture of the full market return, effectively reducing their arbitrage revenue. Longer duration storage (e.g. 6+ hours) are better suited to offering contracts of this nature which can provide returns on the deep storage investment that cannot be fully accessed within an operating day.

Tolling contracts have accompanied some investment in ESS in the NEM, where market dispatch rights are transferred away from the storage owner to the contract counterparty. A notable example of this is the Kidston PHES, who have underpinned their investment with a 40-year contract with Energy Australia who will effectively take all market risk away from the investor (Energy Australia, 2021). The strong desire for tolling contracts is clearly preferable for project lenders, given the effect they have on avoiding market revenue risk.

Other revenue streams receive mixed interest, where portfolio benefits are valued more by Gentailers than others, and system services are currently favoured by synchronous technologies in the present system. The locational benefits that ESS can have on congestion management has been discussed in NEM reform processes, but generally congested locations pose more risk to participants than can be alleviated through proposed mechanisms. Limited opportunities exist for the remainder, with reserve contracts having limited depth, and storage as a transmission asset was added by one respondent (as it was not listed on the survey).

[13] Such as the Federal Capacity Investment Scheme (CIS) and New South Wales Long Term Energy Services Agreement (LTESA)

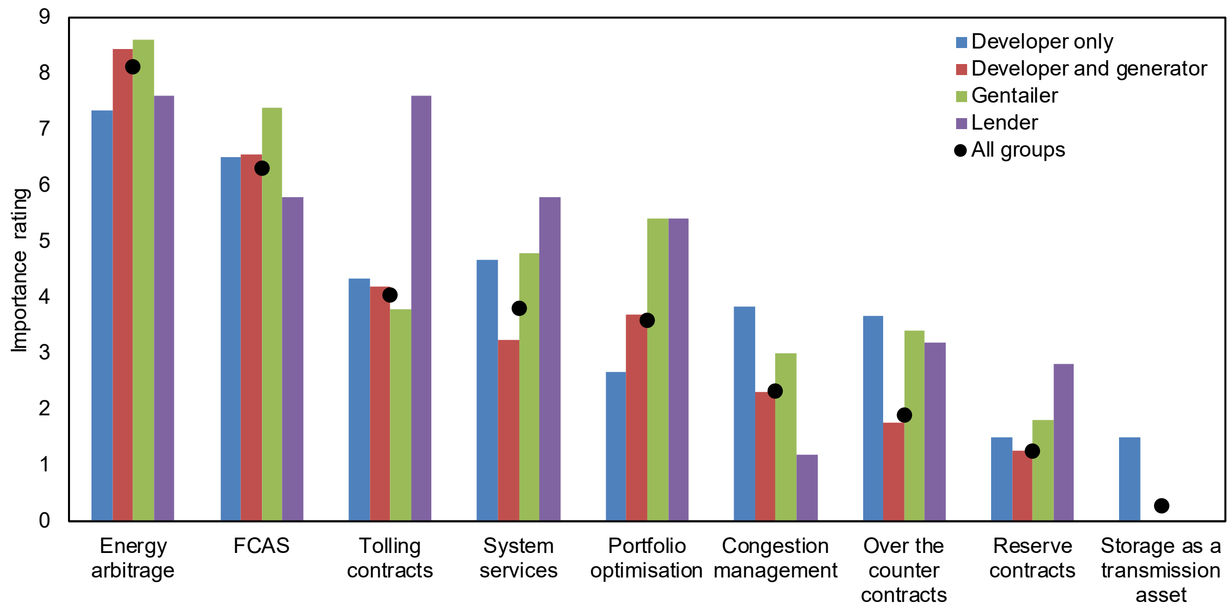


Figure 8 – Target revenue streams for energy storage investments

5.1.2 Barriers to ESS investment

To contextualise current ESS barriers against the literature, rank order survey response has been used. Figure 9 presents the results by weighting, across all groups and by demographic. Technical and non-technical barriers have been jointly assessed to measure their perceived impact. As opposed to using a Likert scale response to assess these barriers, rank order was preferred as it would encourage respondents to identify which of the variables had greater influence.

Respondents attributed insufficient market revenues as being most impactful, with 60% of all respondents ranking this their greatest barrier. Prior research has highlighted that net arbitrage revenues for storage projects can vary significantly from year to year (Abeygunawardana & Ledwich, 2013; Sioshansi et al., 2009, 2012). As the primary revenue focus, the volatility and uncertainty of returns remains a strong deterrent to investor confidence. Relevantly, support for additional markets to compensate for ESS specific services emphasises this point. The potential of ESS services to support power system operations, particularly as VRE market share increases, is currently undervalued (Abeygunawardana & Ledwich, 2013; Hartmann et al., 2019). In the absence of these benefits being rewarded, current market revenues will likely remain inadequate.

Mixed responses were received in relation to technology costs where standalone developers rated this their biggest challenge, but it was considerably lower in other groups. Those with market exposure were less concerned, indicating that costs should be considered in a relative manner to their possible returns. Gentailers, for example, place little emphasis on cost, but consider the benefits that ESS deliver in supporting their portfolio much higher than developers and generators (from Figure 8). This suggests that there are strategic benefits that ESS can provide in portfolio risk reduction where additional value can be realised.

Although low in the ranking of barriers, there were mixed responses in relation to the terms of financing. Naturally this was not perceived to be impactful from the lender perspective as their terms reflect their exposure to risk. As Sioshansi et al. (2012) discussed, the inherent risk (largely related to revenue) associated with an investment will affect the risk premium applied to the cost of capital. To that part, the financing terms reflect how well project risks have been mitigated.

Where Wilson & Hughes (2014) reported that storage investment was being deterred by technical requirements and were not approved service providers, this does not appear to be of significance in the Australian context at this point in time. Targeted regulatory reform has occurred in the NEM in the past decade to overcome ESS barriers[14]. This appears to have had the desired effect, with two of the three technical barriers rated lowest by the respondents. Confidence in the asset class now appears to be high as *unproven technology* this was ranked lowest (or not at all) by 83% of respondents.

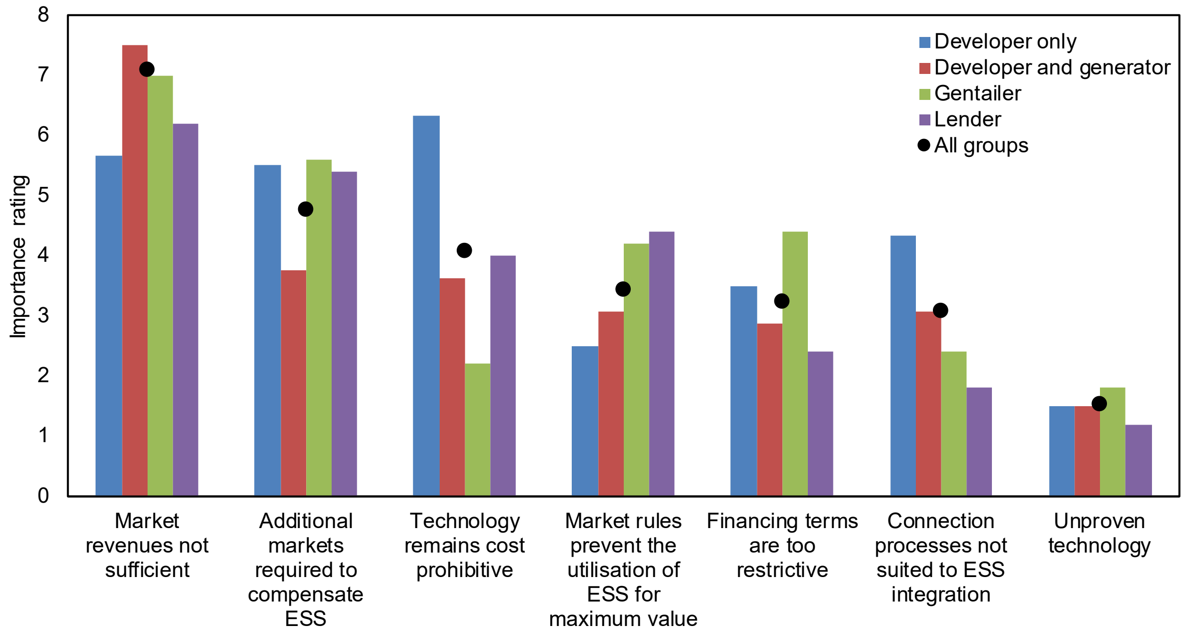


Figure 9 – Investment barriers for energy storage system

5.1.3 Lender's perspective

How capital markets and their practitioners consider project risk has a direct effect on their comfort when financing projects. Seeking the perspectives of the lending professionals has been useful in appreciating where they see key project risks. While relatively few responses were received from this group, this is fair given the relatively small number of organisations that are capable of funding capital intensive power system projects. Their responses were tightly clustered, indicating a consistent view of market conditions amongst respondents. Their focus is clearly on investments that are technologically proven and competitive in the current market. Pumped hydro and lithium-ion BESS operate maturely in the NEM, and significant appetite was noted by lenders. Interest is present in emerging technologies, particularly hydrogen which aligns with long-term decarbonisation objectives which are supported by the finance sector. Their preference is for shorter storage durations that focus on intra-day operations, maximising use of their energy investment. A lack of revenue contracts with long tenor was noted as a barrier, which would appear consistent with their preference for tolling contracts to improve

[14] Particularly the "Integrating energy storage systems into the NEM" rule change, which introduced a new registration category that enabled clarity and efficiency for connections that consisted of bi-directional dispatch and aggregating multiple generating technologies (e.g. wind, solar PV and BESS behind a single connection point).

revenue certainty. Generally, their responses are consistent with a measured risk management approach that is taken by financiers. Their primary interest is in established technologies with known revenue pathways and are aligned with government policies and strategies.

This survey has provided contemporary insights into the trends and challenges facing ESS investment in the NEM. In comparison to the earlier research, it appears that there is greater confidence in ESS technologies, where regulatory and connection barriers (while still present) are not the greatest impediment to investment. Revenue certainty remains the most significant factor affecting investor confidence. There have been strong calls for additional markets to recognise and compensate for the benefits that ESS provide.

5.2 Revenue adequacy and the economics of energy storage

Survey respondents highlighted an appetite to invest in ESS, however the lack of revenue security was repeatedly emphasised as the primary barrier to entry. To understand the extent of this problem, a formal PF Model has been used to assess storage economics in a manner that is broadly representative of a generalised entry cost model and industry-based investment framework. The detailed notation of the PF model is described in McDonald (2023) and appears in Appendix 1, modified to include charging, round trip efficiency and mid-life refurbishment financing. In short, the model functions to calculate the underlying revenues required per dispatched megawatt-hour. To do this, the model uses a linear optimisation function with the objective of minimising costs, while co-optimising project debt and taxation variables whilst meeting an IRR constraint.

5.2.1 Modelling summary

Seven investment cases have been examined across 2-24h storage durations, with technology durations guided by Schmidt et al. (2019). To date, investment in BESS has been at relatively low power capacity and for short durations. It is anticipated that this will gradually increase in the future as capital costs fall. PHES has dominated storage investment historically, but future focus is expected on longer durations as BESS fulfills the shorter-term functions. The PF model inputs are summarised in Table 2.

Table 2 – Project finance model inputs and assumptions

Model inputs		BESS 2h	BESS 4h	BESS 8h	BESS 12h	PHES 8h	PHES 12h	PHES 24h
Technical								
Operating life	(year)	35	35	35	35	50*	50*	50*
Power capacity	(MW)	200	200	200	200	1000	1000	1000
Storage capacity	(MWh)	2	4	8	12	8	12	24
Capacity factor (Gen)	(%)	8.2%	16.4%	25.0%	25.0%	25.0%	25.0%	25.0%
Daily operating hours	(hour)	2.0	3.9	6.0	6.0	6.0	6.0	6.0
Round-trip efficiency	(%)	84%	84%	84%	84%	78%	78%	78%
Degradation	(%)	0.2%	0.2%	0.2%	0.2%	0.0%	0.0%	0.0%
Availability**	(%)	98.5%	98.5%	98.5%	98.5%	98.5%	98.5%	98.5%
Transmission loss factor		1	1	1	1	1	1	1
Expenses								
Overnight capital costs	($/kWh)	$731	$592	$519	$478	$517	$363	$242
Operating costs	($'000/MWh)	$12	$15	$33	$33	$21	$21	$21
Charging	($/MWh)	$25	$35	$42	$42	$43	$43	$42

Mid-life refurbishment	(year)	20	20	20	20	N/A	N/A	N/A
Mid-life refurbishment	($kWh)	$166	$166	$166	$166	-	-	-
Capital cost contingency	(%)	10%	10%	10%	10%	15%	15%	15%
PF model								
Modelling timeframe	(year)	30	30	30	30	30***	30***	30***
Indexation	(%)	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Corporate tax rate	(%)	30%	30%	30%	30%	30%	30%	30%
Hurdle rate (equity, post-tax)	(%)	8%	8%	8%	8%	8%	8%	8%
Debt tenor	(year)	15	15	15	15	30	30	30
BBSW	(%)	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%
Debt margin	(bps)	200	200	200	200	200	200	200
Debt service cover ratio		>1.35x	>1.35x	>1.35x	>1.35x	>1.35x	>1.35x	>1.35x

* Initial design life – 50 years for electrical and mechanical plant, 100 years for civil infrastructure
**Availability includes plant and network outages.
*** A terminal value is applied to account for the extended operating life beyond the modelling timeframe

Review of publicly announced project costs and industry resources (AEMO, 2024a; Aurecon, 2020; Graham et al., 2024) have been relied upon to determine capital and operating expenses, round trip efficiency, degradation and availability assumptions. A common criticism of comparative analysis between BESS and PHES is the life spans assumed for their operations. While the life span of battery modules is governed by charge and discharge cycle limits (typically requiring their replacement after ~20 years), the inverter and balance of plant components are anticipated to operate for up to 35 years. For this reason, the model assumes a mid-life refurbishment to extend the technical operating life. The cost of charging draws on observed average daily minimum price data, with greater energy consumption required on account of the technical round trip efficiency losses. Imperfect foresight is managed by applying an 85% capture rate of optimal charging periods. Capacity factors reflect the technical and economic limits, where warranty restrictions limit BESS to one charge/discharge cycle per day, and up to 6 hours per day for long duration ESS (consistent with the market opportunities discussed in McConnell et al., (2015)).

Financing applies the Bank Bill Swap Rate (BBSW) with a 200-basis point debt margin. Debt is amortised over 15 (BESS) and 30 (PHES) year periods. To optimise cashflow and taxation benefits, the BESS life extension capital expenditure is fully debt funded with a 10-year repayment term. To avoid the tail risk of unplanned outages in late-stage operations, financiers typically require debt to be repaid at least 5 years before the end of the initial design life. The model optimises project gearing to minimise the revenue required to satisfy debt obligations and achieve a post-tax equity return of 8% to investors.

The modelling timeframe is set to 30 years, broadly aligning with the financing limits of commercial debt facilities (Simshauser & Gohdes, 2025) and discounts cashflows across the period. The ultra-long operating life of PHES is acknowledged (100 years on civil, and 50 years on electrical and mechanical equipment), where the debt facility is allowed to amortise over the full modelling period and a terminal value is included for the revenues that go far beyond the analysis period[15].

[15] This does reduce the revenue requirements but severely constrains gearing, where 18% greater equity investment is required upfront compared to a case where no terminal value was included.

5.2.2 Model results

The results shown in Figure 10 presents the minimum revenue required per megawatt hour of energy that is dispatched to achieve the investment prerequisites. With shorter lifespans and higher unit rates for capital expenses, it is no surprise that BESS remains a more expensive investment. Where the 8 and 12h BESS are unable to fully cycle its invested storage capacity each day, the required revenue is greater than its smaller counterpart despite lower unit rates.

The breakdown confirms the importance of optimising the debt structure, with it being a key factor in developing a viable investment. The model results showed that the level of gearing was generally consistent within the technology groups, with BESS (~57-59%) slightly more than PHES (~51%). While opportunities to reduce carrying costs through novel debt structures are not explored in this paper, readers are encouraged to review Simshauser & Gohdes (2025) and Miller & Carriveau (2018) who explore this topic in detail.

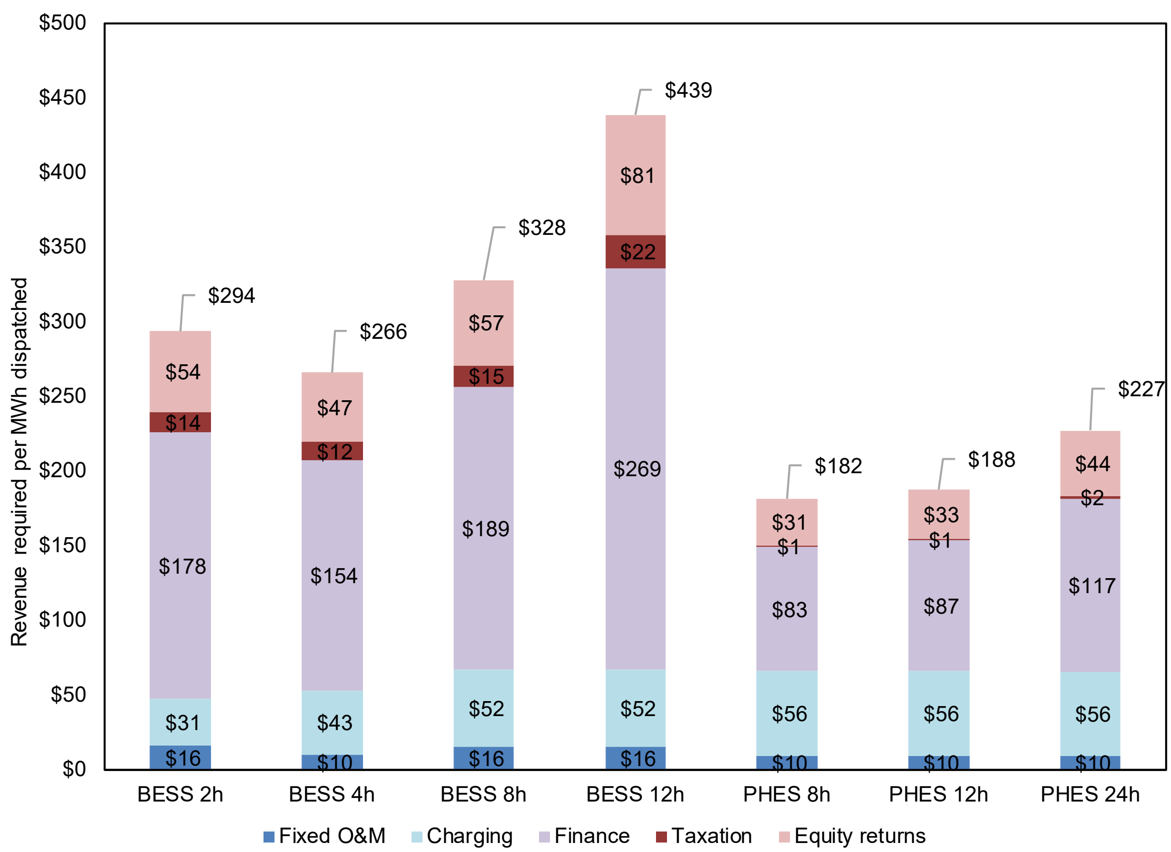


Figure 10 – Revenue requirements for energy dispatched from storage, year 1 breakdown

While economies of scale reduce the capital costs of the longer duration installations (where the energy components have a lower unit rate relative to power components), the benefits are constrained by their inability to regularly monetise their full storage capacity. We see this clearly with the increasing duration of BESS, where the revenue requirements reduce from 2 to 4 hours, but increase again for the 8h and significantly more so for the 12h option. Although the revenue requirements do also increase for PHES, the magnitude is much less. The very long lifespan and financing benefits show that PHES remains the preferred technology for long duration storage. This is an important observation, particularly given our industry feedback that revenue uncertainty is plaguing long duration storage appetite. Despite lower relative capital costs ($/MWh) and higher utilisation, the longer duration ESS are at a distinct disadvantage to their smaller counterparts.

Dispatch behaviour and resource adequacy are worth remembering when considering these results. As there is no direct consequence for system collapse on generators, profit maximisation will drive behaviour. In short duration assets, the technical incentives (i.e. BESS warranted cycling limits and very fast response capabilities) push operators towards the highest and lowest price periods only. As duration increases, the intra-day price spread narrows and provides less economic opportunity to dispatch the stored energy. But, if revenue requirements remain less than the available price spread, long and stable periods of output can occur in support of network stability. The ability to generate for extended durations without the need to maintain a daily cycling balance requires additional investment to be carried over extended periods without compensation.

While there is inherent value to the whole system in maintaining energy storage capacity beyond just intra-day operations (renewable energy droughts, insurance value and managing tail risks), it is not reflected clearly by our decision-making and analytical frameworks, nor through existing market mechanisms. We also observe this shortcoming in other comparison tools, such as the levelised cost of storage, where there is a clear preference for assets that can access all their stored capacity within a single operating day.

5.3 Revenue adequacy for ESS in the NEM

With the revenue requirements now defined, we can assess whether there is sufficient opportunity for market revenues to the satisfy investment criteria. Drawing upon data from section 2.3 and 5.2, we assess the revenue adequacy across the established revenue streams.

Consider first, the reliance on spot market arbitrage revenues (Figure 11). Across the analysis period, market revenues were insufficient to support any merchant investment through arbitrage revenue alone. Taking the maximum hourly prices over the analysis period, none of the investments would have achieved the average required revenue, even with perfect foresight. Only two out of the eight years produced the required revenues to sustain most ESS investment, highlighting the persistent volatility and uncertainty in annual revenue. Not even in the 2022 energy crisis were conditions sufficient to sustain 8 and 12 hour BESS, signalling the challenges anticipated for this investment.

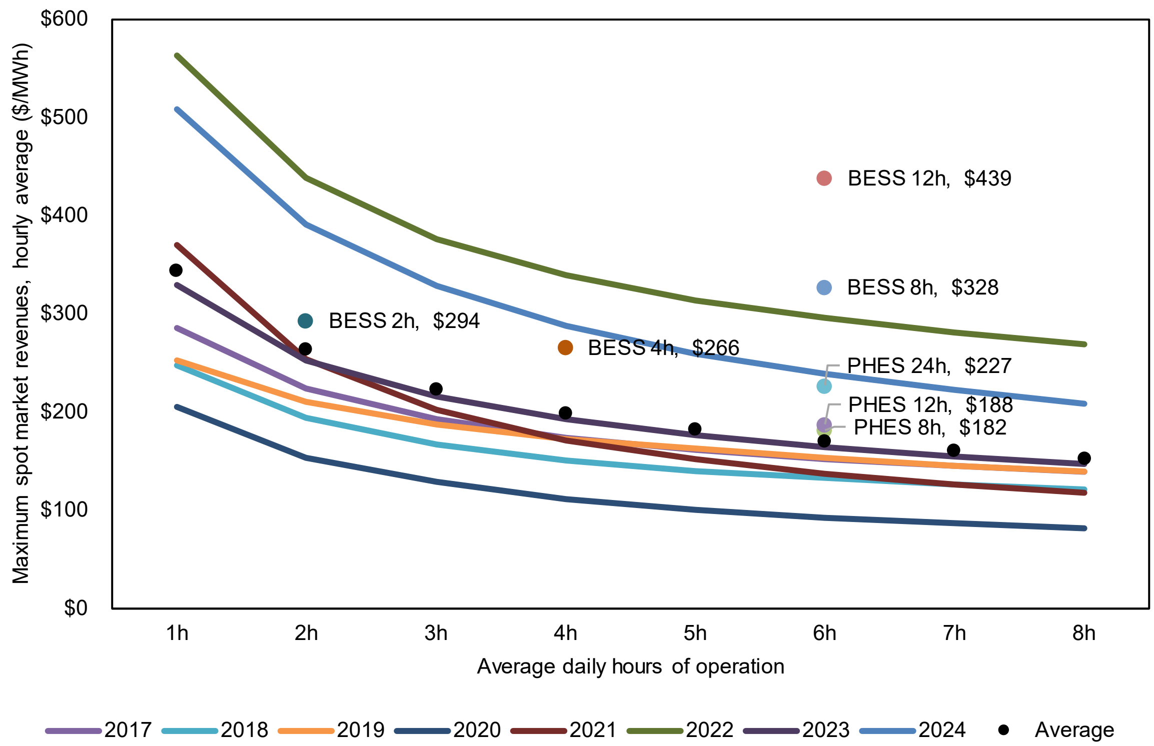


Figure 11 – NEM average maximum hourly spot prices

As the perfect capture of maximum prices is not possible, an 85% capture rate is applied, with a 15% weighting of the next hourly prices. This is still considered quite optimistic (given maintenance requirements, transmission outages, etc), however is used to illustrate the challenges in revenue certainty. Across the range of investment options, Table 3 shows that energy arbitrage alone has provided inadequate revenues to support any of the ESS investments. This is not surprising as early movers have targeted opportunities in the FCAS market, with arbitrage being secondary. However, with increasing competition and a shallow pool, FCAS will continue to be secondary.

Table 3 – Investment shortfall from energy arbitrage revenue

Revenues ($/MWh)	BESS 2h	BESS 4h	BESS 8h	BESS 12h	PHES 8h	PHES 12h	PHES 24h
Required	$294	$266	$328	$439	$182	$188	$227
Available from spot market*	$259	$198	$170	$170	$170	$170	$170
Shortfall	**-$35**	**-$68**	**-$159**	**-$269**	**-$12**	**-$18**	**-$58**

* 85% perfect capture rate

Table 4 gives us greater perspective of the full investment decision and the benefits of revenue stacking. Consistent with current market conditions, a modest level of FCAS revenue has been assumed which aligns with growing competition in this market[16]. PHES is not considered to play

[16] For simplicity, contingency services are considered as they compensate for available capacity and do not materially reduce the daily energy available for arbitrage.

a significant role in FCAS markets into the future, particularly as their relative scale would mean the revenues would not be material. Though, with increasing storage capacity the opportunity to offer and defend cap contracts grows. While stable revenues via the cap premium are beneficial, it does reduce the potential upside during periods of high market volatility[17]. For the 8h options, it's assumed that 50% of their power capacity has been contracted, and with greater confidence the longer duration options contract 75%. These hedging practices will have benefits for debt funding and associated terms, but these are not considered any further here.

After inclusion of the additional revenues, arbitrage requirements drop between 11-25%. Being well suited to providing FCAS, short duration BESS makes the most notable improvement, achieving revenue adequacy for the 2h BESS. This aligns with observations across the period where the NEM has seen considerable market led investment in this asset class. Extending to 4h, where several projects are in construction and many more reaching financial close, returns drop to 6.4%. With government contracts reducing financier risk, effective debt structuring likely means that these returns are still palatable (or being supplemented through underwriting schemes).

Drawing the reader's attention to the BESS 8 and 12-hour options, the requirements of the fully merchant scenario (Table 3), show revenue requirements exceeding \$300/MWh. This should preclude the BESS from offering cap contracts as it cannot afford for market revenues to be suppressed above the strike price. However, we do see some benefit in the regular revenues provided through the cap premium, but where on-market revenues are reduced for the contracted portion, we see a large and stubborn revenue shortfall. In comparison to its PHES counterparts (who do not have these same limitations), we see the effect of higher capital costs (on a unit rate basis), shorter lifespan and debt amortisation period. It is considered that long duration BESS is intractable in the current conditions.

While cap contracts have been the focus of this analysis, PHES are well suited to offering a range of hedging products. For the smaller PHES cases, total revenue shortfalls are relatively small on a per MWh basis, but on investments of this scale would require additional equity investment to overcome debt conditions. The effects on the 8-12 hour PHES are ~3% reduction in gearing and reduces equity returns to ~7.5%. The 24h PHES faces bigger challenges with 14% reduction in gearing and equity returns to 5.4%. The risk lies in the absolute magnitude of these shortfalls (up to \$101m p.a.) and the associated debt serviceability issues, where each project would face lockup and cash sweeps without additional equity injections. Where PHES projects benefit from efficiency at large scale, they face extended development and construction timeframes (with significant risk within), demand significant equity investment and uncertain monetary policy conditions before a single MWh is produced. Adding even a small level of revenue uncertainty presents a substantial hurdle for market led investment.

Table 4 – Investment shortfall from established revenue streams

Technology	BESS 2h	BESS 4h	BESS 8h	BESS 12h	PHES 8h	PHES 12h	PHES 24h
Revenue required (\$/MWh)	***\$294***	***\$266***	***\$328***	***\$439***	***\$182***	***\$188***	***\$227***
FCAS							
Annual revenue (\$'000)	\$3,725	\$3,725	\$3,725	\$3,725	\$931	\$931	\$931
Cap contracts							
Capacity contracted (%)	0%	0%	50%	75%	50%	75%	75%
Cap premium revenue (\$'000, p.a)	\$-	\$-	13,341	\$20,012	\$66,707	\$100,061	\$100,061

17 Where spot market revenues are capped at \$300/MWh

Remaining revenue required ($/MWh)	***$243***	***$229***	***$256***	***$334***	***$150***	***$141***	***$181***
Available from spot market*							
Merchant	$259	$198	$170	$170	$170	$170	$170
Contracted	N/A	N/A	$123	$123	$123	$123	$123
Weighted average spot revenue	$259	$198	$146	$135	$146	$135	$135
Revenue balance ($/MWh)	**+$16**	**-$31**	**-$110**	**-$199**	**-$4**	**-$6**	**-$46**

* 85% perfect capture rate

This provides a detailed understanding of the landscape for market led investment in ESS using the existing revenue streams available in the NEM. This demonstrates in very real terms, the level of revenue inadequacy that is blocking investment in longer duration storage developments. The detailed insights that the PF model provides also highlight the crucial relationship that revenue adequacy has on debt and financing conditions. This emphasises the point made in Simshauser & Gohdes (2025), that avenues should be explored[18] to de-risk projects revenues and enable greater security for project financiers. Where services are provided that benefit the power system, new compensation mechanisms should be developed, otherwise ESS investment will continue to lag.

As this analysis has been completed on historic market conditions, it does not consider the viability of future market conditions nor the price effects that additional capacity would have had. While volatility has trended upwards across the period, concerns over energy affordability is filling mainstream and industry media. With heightened volatility comes an increasing need for retailers to hedge their portfolio, which flows through to consumer costs. It is difficult to foresee that the required market conditions will be allowed to manifest without political intervention occurring.

It is important to also note that the operating assumptions have been intended to maximise plant utilisation and output, thereby minimising the revenue requirements on a per-unit basis. While publicly available business case data[19] forecasts higher capacity factors than currently observed by long duration storage in the NEM (<10%), this adds further uncertainty for investors. Another limitation it that the serviceability constraints and other financing conditions may have been understated for the level of merchant operations assumed.

5.4 Market and policy frameworks

This section proposes mechanisms to address coordination problems and new revenue streams for ESS investments.

5.4.1 Coordination of storage resources

Drawing attention back to section 2.1, recall that the lack of coordination of ESS is presenting challenges in various jurisdictions regardless of their market design. For energy-only markets, various complementary mechanisms have been suggested to overcome their inherent limitations, originating with Hogan's (2005, 2013) consideration of operating reserve markets. In a similar light, a new market model is suggested here as a means of addressing the lack of spot market coordination and to overcome the revenue uncertainty affecting ESS investment in the NEM.

[18] In their case, semi-regulated operations enabled credit-wrapped facilities to optimising funding arrangements.
[19] Snowy 2.0 updated business case suggests ~28% ACF, and Kidston ~20-30%

The Day-ahead Storage Commitment Market (DSCM) functions as a forward capacity commitment mechanism, designed to provide specific and adaptable incentives around the state of charge and mode of operation of ESS at specific points in time. While similar to an operating reserve market, the proposed DSCM commits the resources sufficiently far ahead of real time dispatch to enable them to effectively manage their state of charge (cf. state of charge in real time operating reserve markets are based on existing storage levels). This market could operate in an always on, or triggered depending on the market or operating thresholds. The following logic is proposed:

- The DSCM would function as a bi-directional service (load and generation), specifically targeting energy storage systems.
- Time periods and required volumes are specified by the market operator the day ahead of the requirement.
- Participants offer to commit their availability at their preferred time on a competitive price basis, with dispatch price triggers (i.e. bidding their DSCM premium value and committing their energy dispatch price for merit order sequencing)
- Committed resources would be selected via a least cost economic dispatch.
- Participants would be notified of their committed quantities and timing, allowing their state of charge to be managed accordingly.
- Payment of a DSCM premium (being the marginal price of the final committed provider) would be provided to all committed participants. This premium would be paid for the committed capacity, regardless of whether the market operator elects to dispatch the unit.
- Any dispatched energy would be compensated through the real time energy market.
- Penalties would be applied for failure to deliver (above their market purchase of undelivered energy).

On this basis, the DSCM would provide the market operator with additional means of managing the network within its operating limits. Acknowledging that there can be significant variability between day ahead forecasts and real time conditions, the intent of the DSCM is to coordinate storage state of charge and continue to allow the spot market to value real time supply. Procured volumes would be adjustable based on system related needs (e.g. minimum load, network contingency risk), and the market operator may elect not to dispatch the committed energy if forecast conditions do not transpire. Participants would retain the right to dispatch their energy at the committed time, however they would be a limited by their dispatch price trigger.

5.4.2 Analysis of the DSCM

When load is being procured in the DSCM, dispatch occurs on the following basis:

Eq. 1. $D'(t) = D(t) + L_{DSCM}(t), \quad \text{where } t \in [0, x]$

Where:

- t denotes the time where the DSCM load period applies, $t \in [0, x]$
- $D(t)$ represents the original energy demand at time t,
- $L_{DECM}(t)$ is the procured DSCM capacity for time t, and
- $D'(t)$ is the new energy demand after the addition of the DSCM load.

The resulting spot market price, $P'(t)$, with the inclusion of the DSCM committed capacity is represented as:

Eq. 2. $P'(t) = P(D)_t + P(DSCM_L)_t$

Where:

- $P(D)$ represents the electricity price as a function of initial market demand,
- $P(DSCM_L)_t$ is the marginal cost of the DSCM committed capacity.

In contrast, when generation capacity is procured, the DSCM does not alter market demand but alters the marginal cost of dispatch:

Eq. 3. $P'(t) = P(D - G_{DSCM})_t$

Where the procured capacity is defined as G_{DSCM}. The price impression effect of the generation DSCM simulates the market outcomes at a lower demand level, without physically altering consumption.

Ex-post analysis of load and generation in the Queensland region of the NEM has occurred to simulate the operation of the DSCM. Anticipated market outcomes have been derived from AEMO's pre-dispatch price sensitivity forecasts for each half-hour period from 1 November 2023 to 30 October 2024. The analysis considered two daily DSCM periods, with 500MW of load procured from 10am-2pm, and 500MW of generation from 6pm-10pm. In this scenario, it is assumed that DSCM committed capacity are price-taking in their dispatch.

The operation of the DSCM is shown in Figure 12 across an average daily operating profile. When procuring a consistent daily volume through the DSCM, there is a noticeable shift in market outcomes. The average market prices across the period show an increase in daytime (DSCM load) prices, and reduction in evening peak (DSCM generation) prices. It should be noted that increased demand will still allow peaking generators to access scarcity rents, regardless of the DSCM. This is an important aspect of its design, where generators are not prevented from being adequately compensated for their supply when market conditions are tight.

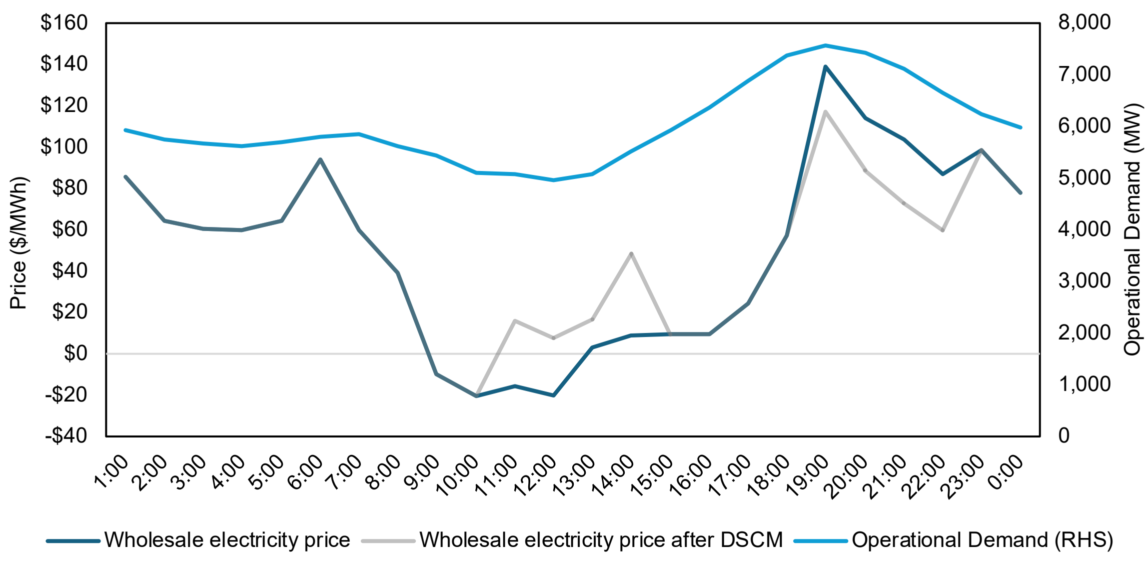


Figure 12 – Average Queensland wholesale electricity prices with the DSCM

Table 5 summarises the market effect of the DSCM over the analysis period. By coordinating the charging of energy storage devices across the peak solar supply period, output weighted prices (OWP) increase by $34.89/MWh, which is more than offset by the reduction in evening peak OWP by $64.53/MWh. This market outcome produces a consumer surplus of $343M p.a, across a single year of operations. Where the Queensland region of the NEM accounts for ~28% of total consumption (AER, 2025), the benefits of the DSCM could exceed $1.2B p.a.

It is anticipated that providers would not commit their full capacity into the DSCM but would encourage their commitment during periods they would intend to participate anyway. With autonomy remaining with the participant, it is anticipated that they would seek to capture their SRMC through the DSCM premium and pursue upside from the energy market. On this basis, the application of the DSCM should provide sufficient savings from the market to cover its costs.

Table 5 – DSCM summary

Market turnover pre-DSCM	Market turnover post-DSCM	Regional demand	DSCM volume	Market saving
$5,623M	$5,280M	54,813GWh	1,460GWh	$343M (6.11%)

Investment conditions are becoming increasingly challenging for project financed solar PV projects given the persistent negative prices and lack of appetite for run of plant PPAs. The continued operation of must-run coal and concurrent output from price insensitive distributed PV is already stalling investment and setting the scene for critical minimum load problems (Simshauser & Wild, 2024). The DSCM provides additional benefits in this situation through the coordination of flexible load through the middle of the day and improving on-market support for new generating capacity.

5.4.3 Storage certificate scheme

Investment in VRE in the NEM has benefited greatly from the Renewable Energy Target (RET), which commenced in 2001. The scheme enabled the creation of large-scale generation certificates (LGC) by eligible renewable energy generators, where liable entities would procure (then surrender) sufficient LGC to cover the required percentage of their load base. As the current form of the RET is set to conclude at the end of 2030, the mandated requirement (and their induced value) for certificates will cease. However, the need for evidence of emissions-free electricity remains[20]. To replace the RET certificates, the Guarantee of Origin Scheme (GO Scheme) has been legislated Federally, which will enable evidence of emissions-free energy usage. This scheme provides higher resolution certificates (through timestamping), broadens the scope of eligible participants (to include hydrogen production and energy storage), and enables greater supply chain participation (where the RET has primarily been focussed on NEM based operations). As a voluntary scheme, the intention has been to encourage broader participation to demonstrate emissions-free production across the supply chain to support international trade (McMaugh, 2024).

As the RET had specifically excluded ESS, there has been no certificate-based scheme to drive its investment. Given the success of certificate-based schemes in the NEM, calls have been made for storage specific schemes to be implemented with mandatory targets. As an example, Mountain et al. (2022) suggested a target-based scheme where storage providers would be allocated certificates based on their installed capacity and supply reliability, with mandated obligations placed on relevant entities (e.g. retailers). In designing the GO Scheme, no obligations of this nature have been defined.

[20] Global trade will increasingly be influenced by carbon-based tariffs such as the carbon border adjustment mechanism which places a price on carbon emitted during production of emissions-intensive goods that are imported to the European Union.

The inclusion of storage into the GO Scheme is useful in demonstrating its relevance in supply chain emissions accounting, yet it is only through downstream legislation that participation may be encouraged. Implied value may be given to ESS certificates if the risk of penalties through trade tariffs or restrictions exceeds the value of the certificate. However, the scheme requires REC's to be surrendered for GO Scheme certificates to be subsequently created for ESS as well as accounting for their RTE losses (Commonwealth of Australia, 2024). If there is insufficient spread in time-based certificate value (analogous to intra-day electricity price variation for energy arbitrage), the certificates add an unmitigated cost to ESS participants. This places ESS at a distinct disadvantage that will likely disincentivise participation and fail to stimulate investment.

In Figure 13, we simulate the effect of participation in the GO Scheme on our seven ESS projects. Assuming the current value of LGC is added to the cost of charging (Q3 2024, $44.89/certificate; Clean Energy Regulator, 2024), and the requirement to procure more certificates than will subsequently be created (as a result of RTE losses), we see increases to the revenue requirements by 12-32%. In the absence of any specific value being created through this scheme, this effectively forms a type of taxation on ESS participation and adds deadweight loss to their efficiency. This would likely disincentivise participation (particularly for longer duration storage) so they can maintain their competitiveness against other generation sources. On this basis, the current framework does not appear suitable for ESS participation, nor will it promote investment. While the scheme may have sought to avoid picking winners[21], it may well have picked a loser.

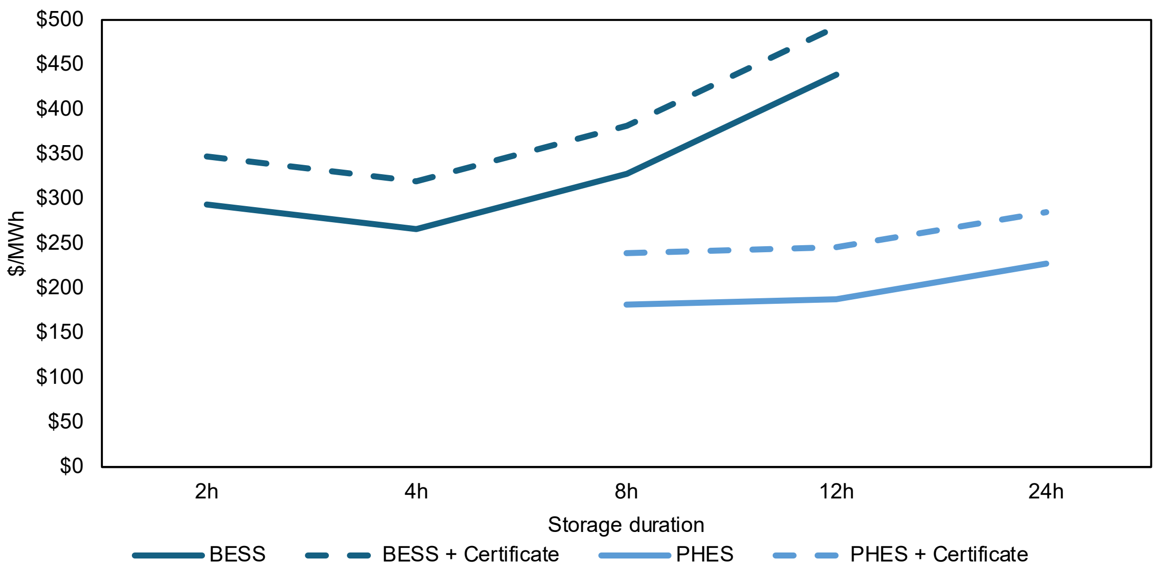


Figure 13 – Energy storage system revenue requirements with GO Scheme participation

5.4.4 DSCM storage certificate scheme

Effective storage certificate schemes should be designed to value storage availability, not output (Mountain et al., 2022). Leveraging the coordination and efficiency benefits shown in section 6, it is proposed that a certificate scheme function in parallel to the DSCM where certificates are created through its participation. In a similar fashion to the annual renewable power percentage

[21] Although it has arguably been framed directly around Hydrogen production

defined under the RET, a storage capacity percentage (administratively banded across a portfolio of durations) could be defined and mandated for liable entities. This would provide a clear framework to incentivise storage investment and provide performance incentives for its availability when the market requires. The nature of the DSCM dispatch would further encourage competition and efficiency.

Considering this in practice, the storage volumes have been expanded to align with the forecast grid scale storage requirements set out in AEMO's Integrated System Plan (2024). Their modelling categorises storage into short (<4h), medium (4-12h) and long (>12h) durations. Administrative banding of the certificate scheme would be needed to guide investment across storage categories as needed. This approach has been used previously in the evolution of the Renewable Energy Target to avoid crowding out and encourage long term development across a range of technologies.

The expanded DSCM capacity requirements are shown in Figure 14, with availability, capacity factor and round-trip efficiency assumptions consistent with Table 2. In this scenario, certificates are created for each MWh committed to the DSCM (either through consumption or generation).

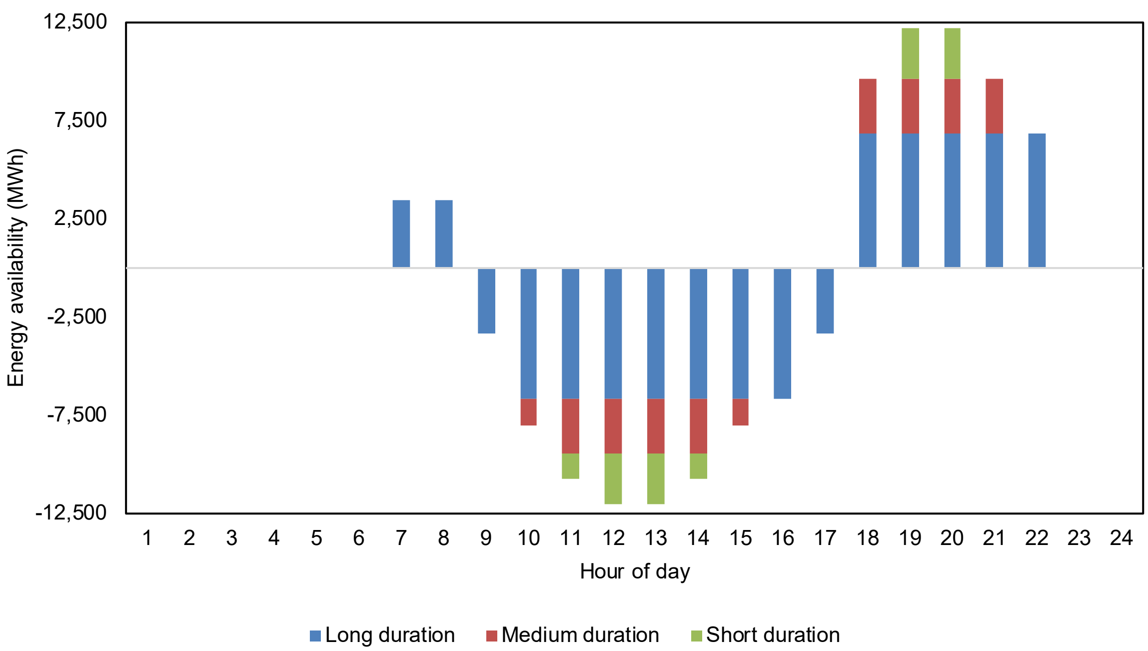


Figure 14 – Stylised DSCM storage commitments across duration categories

Where the DSCM premium focusses on coordination, a complementary certificate scheme would target the revenue uncertainty that is inhibiting investment. The following equation shows the revenue outcomes from the commitment of capacity to the DSCM.

Eq. 4. $R_{ESS} = \sum_{t=0}^{x} DSCM_{(t)} \cdot (\pi DSCM_{(t)} + Pc(t)) + E \cdot P'(t)$

Where:

- R_{ESS} is the revenue for the ESS during the DSCM time periods,
- $DSCM_{(t)}$ is the quantity of capacity committed in either G_{DSCM} or L_{DSCM} markets
- $\pi DSCM_{(t)}$ is the DSCM premium payable
- $Pc(t)$ is the price attainable for certificate $C(t)$
- E is the energy transferred (in MWh) by the ESS during the DSCM period (noting that operations may be zero if not dispatched or negative when charging), and

- $P'(t)$ is the electricity price with the inclusion of the DSCM committed capacity.

To provide the necessary signals for investment, the required certificate value must exceed the missing money set out in Table 4. These results offer storage solutions that are revenue adequate for short duration (2h BESS) and nearly adequate for medium duration (8-12h PHES), so this analysis will focus on long duration storage where the greatest revenue shortfall exists. To evaluate the potential annual costs of a long duration storage scheme, the 24h PHES has been used. For certificate creation (across both the charge and discharge functions of the DSCM) availability is assumed for 13.5h/day. The required certificate value and annual scheme costs required to overcome the missing money are given in Table 6. This shows that the total missing money for the required for long duration storage investment totals $670m per annum.

Table 6 - Storage certificate scheme

Storage duration	MW	MWh	Daily certificates	Certificate value ($)	Annual scheme cost ($m)
Long (>12h)	6,680	475,560	90,109	$20.37	$670

Recall from section 6, the anticipated NEM wide benefits from storage coordination through the DSCM for a 500MW/8h procurement could reach $1.2B annually. With expansion of the DSCM to accommodate the storage requirements set out here, the market benefits would be expected to grow. As such, the DSCM combined with a storage certificate scheme offers for a cost-effective means of overcoming the coordination and missing money problems facing ESS investment.

It may be argued that the least cost operation of the scheme would occur if certificate value did not change across categories. If this were the case, disproportionate support would be given and likely leaving the missing money and investment problem unsolved. Further, this does not recognise the changing role that storage plays as its duration increases. Where short duration assets focus on ancillary services and daily peaking, medium duration performs a more stable intra-day firming role, and long duration firms and offers multi-day supply and insurance value, the importance of a portfolio of storage investments should not be overlooked. An important aspect of designing a storage certificate scheme is recognising these characteristics and compensating accordingly. As such, the design of the DSCM scheme should be administratively banded, as set out in this analysis. This will provide the system operator with the required tools to coordinate storage resources and target investment.

Where certificate value is implied by the risk of regulatory penalties for liable entities, this analysis has demonstrated that there is significant market value created through the DSCM. This allows ESS to be compensated fairly for the benefits it provides towards real time resource adequacy and improvements in efficiency. These benefits flow through to liable entities and consumers through stable market prices and reduced volatility. With the mandated obligations of the certificate scheme, it is anticipated that targeted, scalable, and efficient stimulus will be provided for ESS to reach the optimal level of capacity and duration.

6. Discussion

This research has presented the current investment landscape for energy storage projects in Australia and has ranked the most impactful barriers challenging the industry. This comes at an important time for policy makers, where investment is required ahead of the eventual retirement of aging coal generators. In efforts to decarbonise, the variability of wind and solar requires storage and other firming capacity to maintain a reliable energy system. This research demonstrated that the current market is not delivering the necessary revenues to sustain investment.

Industry investors have shown a keen interest in ESS opportunities, however persistent barriers remain. There is a strong focus on lithium-ion BESS and PHES technologies, and storage durations have increased from <2 hours towards 4 hours, with limited interest beyond 12 hours. Although revenue adequacy has been established for short duration batteries, the greatest barrier to investment remains revenue uncertainty, where on-market revenues are not considered sufficient. Calls for additional markets and revision of market rules to maximise the value of ESS are prevalent. While some respondent groups still consider the technology costs to be prohibitive, progress appears to have been made in overcoming the technical and connection barriers that have been observed in prior research.

The analysis confirms survey feedback that ESS projects are missing money when reliant on established market revenue streams. Only in two of the last eight years would arbitrage revenues have been sufficient to sustain five of the seven ESS investment classes. When stacking revenues, the missing money problem is resolved for 2h BESS, but remains below the threshold necessary for market-based investments in longer duration developments. The high capital cost and their financing requirements leaves 8-12 hour BESS well beyond feasibility.

With this information, we see that there is a clear need for policy makers to intervene. Their focus has been on broad-brush programs that remove investor risk by underwriting revenue floors, rather than seeking on-market solutions. As these schemes continue to drive investment towards short duration storage, there is a risk of locking out investment in cost effective, long duration options (as demonstrated in Figure 10) due to the long development timeframes required for their delivery. Other research has shown that there is a social benefit achieved by ESS investment, aligning with government and policy objectives with consumer welfare benefits outweighing capital costs. With this in mind, there is a valid argument for targeted policies that suit energy storage projects.

This work has highlighted that multi-technology schemes (particularly the GO Scheme) are not well suited to stimulating ESS investment. The benefits of the DSCM and its grouping with a storage certificate scheme, goes a long way towards overcoming the coordination and missing money problems. The competitive tension that is present through the bidding process, helps avoid the distortions that can result from purely out of market schemes. By mandating an energy storage volume, demand for a deeper pool of storage certificates will help targeted investment. Administratively, this will fit well with existing RET processes and the developing GO Scheme. With these mechanisms in place, greater demand to contract ESS services would provide the types and depths of contracts needed to overcome financing barriers highlighted in this research.

7. Conclusions

This research has provided important and timely insights into the confidence that investors have in energy storage projects in the NEM and the barriers that are inhibiting market-led investment. Building on prior research, the technical and non-technical barriers to ESS investment from the past decade have been benchmarked through a targeted survey of active industry investors. It has shown that confidence in the technical capability and integration of energy storage into modern power systems has grown, however more work is required to compensate for the services that energy storage offers.

A detailed analysis of mature storage technologies has shown that missing money is plaguing much needed development of capacity. Although arbitrage opportunities have grown across the analysis period, concern is growing over market volatility and energy affordability. This analysis has shown that even greater volatility would be necessary to sustain arbitrage-based investment in ESS, however it is unclear if this will be allowed to eventuate.

Adjustment of the current market settings will be necessary to achieve the level of energy storage investment required to complement the increasing share of VRE in the NEM. This research has introduced options to assist in overcoming the coordination and missing money challenges that are facing system operators and investors. Where the spot market compensates for energy production, more needs to be done to remunerate the services required in an increasingly dynamic system.

The risks associated with inaction are growing, as aging generators pose reliability risks through unplanned outages and uncertainty over their longevity. Their withdrawal without sufficient replacement capacity will produce cost shocks that inevitably flow through to consumers. Through this research, policy makers have been provided useful insights into the investor mindset and areas requiring attention to encourage this much needed technology class.

Appendix 1. PF Model summary

The PF model can be used to manage investment variables to optimise long run marginal costs and allows analysis of variable sensitivity and risk. The PF model is calculated as follows:

Costs (π_t^C) and revenues (π_t^R) are escalated in each period (year) *t*, at the assumed rate of inflation (CPI):

(1) $\pi_t^C = \left[1 + \left(\frac{CPI}{100}\right)\right]^t$, and $\pi_t^R = \left[1 + \left(\frac{CPI}{100}\right)\right]^t$

Total energy output (Q_t) is presented in megawatt hours and is calculated using the installed capacity *k*, annual capacity factor *ACF*, and the number of hours (*h*) in the period.

(2) $Q_t = k \cdot ACF \cdot h$

Dispatched energy q_t is reduced by losses that occur up to and including the connection point including the forced outage rate (*FOR)*, auxiliary load (*Aux*), and the marginal loss factor (*MLF*) for the given period:

(3) $q_t = Q_t \cdot [1 - \Sigma(FOR + Aux)] \cdot MLF_t$

The PF models seeks to determine the minimum electricity price required to achieve the investment hurdle rate, which is considered to the plant's long run marginal cost. This minimum electricity price (*LRMC)* is calculated for year 1 and escalated in ongoing periods using equation (1). Revenues at time *t* are calculated using the dispatched energy and *LRMC*, escalated to present dollars.

(4) $R_t = (LRMC \cdot \pi_t^R)\, q_t$

Annual operating expenses (*OPEX$_t$)* include fixed operations and maintenance costs (FC_t) of the plant are applied on a $/MW rate to the installed capacity (*k*), and variable operating costs (*VC$_t$*) which are applied on a $/MWh basis to the volume of energy required to charge the storage system, subject to round trip efficiency losses. Escalation again occurs using equation (1).

(5) $OPEX_t = (FC_t \cdot k + VC_t \cdot q_t)\, \pi_t^C$

Earnings before interest taxes, depreciation, and amortisation (*EBITDA*) at time *t* is calculated as:

(6) $EBITDA_t = R_t - OPEX_t$

Initial plant capital costs ($CAPEX_0$) are considered to be incurred overnight in Year 0. Where ongoing capital expenditure occurs ($CAPEX_t$), these costs are considered real in the year that they are incurred (i.e. not subject to cost escalation). As capital costs are subject to tax depreciation across their useful life (*L*), the straight line depreciation (D_t) provides a linear markdown towards its residual value (*R*), in the given period is calculated by:

(7) $D_t = \left(\frac{CAPEX_0 - R}{L}\right) + \left(\frac{CAPEX_t - R}{(L - t)}\right)$

The debt financing portion of the PF model calculates the principal (P_t) outstanding and interest (I_t) repayments as the debt amortises across a period less than its effective life. Although the PF model is capable of separating the debt facility into multiple tranches with periodic refinancing, to fully appreciate the current entry cost shocks and future macroeconomic uncertainty, a single tranche with fixed interest rate (*i*) across the term has been applied. For simplicity, repayments are calculated as an annuity (*n*), across the loan term (*T*). The total repayment (RP_t) in each period is:

(8) $RP_t = P_t \frac{\frac{i}{n}\left(1+\frac{i}{n}\right)^{t \cdot n}}{\left(1+\frac{i}{n}\right)^{t \cdot n} - 1}$

Where the interest repayment (I_t) portion is given by:

(9) $I_t = P_t \cdot \frac{i}{n}$

Where refurbishment capital expenditure is debt funded, equations 8 and 9 are repeated, commencing in the year the costs are incurred.

At this point, taxation occurs on earnings less the depreciation and interest. The tax obligation (τ_t) is calculated at the nominal corporate tax rate (τ_c).

(10) $\tau_t = (EBITDA_t - I_t - D_t) \cdot \tau_c$

To ensure adequate cash flow, a debt service over ratio ($DSCR_t$) of >1.35x is required to be maintained to avoid lock-up and potential lender intervention. To monitor this, cash available for debt service ($CAFDS_t$) is found by:

(11) $CAFDS_t = EBITDA_t - CAPEX_t - \tau_t$

Where $DSCR_t$ in a given period is then determined by:

(12) $DSCR_t = \frac{CAFDS_t}{RP_t}$

The investment decision is made based on the net present value of the post-tax return on equity (ROE_t) across the project life. The equity returns in a given period are given by:

(13) $ROE_t = CAFDS_t - RP_t$

Where the equity Net Present Value (NPV_E) of a given hurdle rate (h) across the expected life (L).

(14) $NPV_E = \sum_t^L \frac{ROE_t}{(1+h)^t}$

Finally, the PF model is designed with the following objective: minimise $LRMC_0$, while satisfying the constraints of: $NPV_E \geq \$0$, $DSCR_t \geq 1.35$, and optimal debt level (with a maximum bound of 80%).

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