

Energy storage

Financing speed bumps and opportunities





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Overview

The Australian energy market is undergoing national scrutiny over its changing generation mix. The transition from centralised to decentralised generation is well underway. Innovative technology and alternative solutions (including energy resources embedded at strategic locations within the network or ‘behind the meter’) have a key role to play in shaping Australia’s future energy market.

High penetration of intermittent renewable energy generation is contributing to energy reliability and security concerns.

Government policies are aiming to reduce wholesale energy prices.



Decommissioning of aged coal and gas generation assets are reducing baseload supply.

Gas supply shortages and restrictions on exploration and development are contributing to high current and forecast wholesale gas prices.

Following the recent unprecedented renewable energy boom, 2019 is set to focus on how renewables can transform Australia’s energy generation mix. This is not being driven by ideology, but by economics. Energy storage will play an important role in this transformation. PwC is assisting various energy stakeholders, ranging from equity investors, banks, generation developers, technology pioneers, and commercial and industrial (C&I) consumers, to navigate the complex energy market and inform investment decisions.

In this paper we assess the financial framework surrounding utility-scale energy storage developments and identify the key obstacles to investment from the private sector. In particular, we analyse:

1. Uncertainty in forecasting revenues
2. The uncompensated benefits of improved loss factors and reduced congestion to surrounding projects
3. Additional benefits that energy storage assets can provide
4. A potential framework and solution for asset ownership.

Challenge 1: Uncertainty in forecasting revenues

Private sector infrastructure investment requires a level of certainty and stability in forecast cash flows to support investment decisions. In the absence of both of these, commercial investment becomes unfeasible.

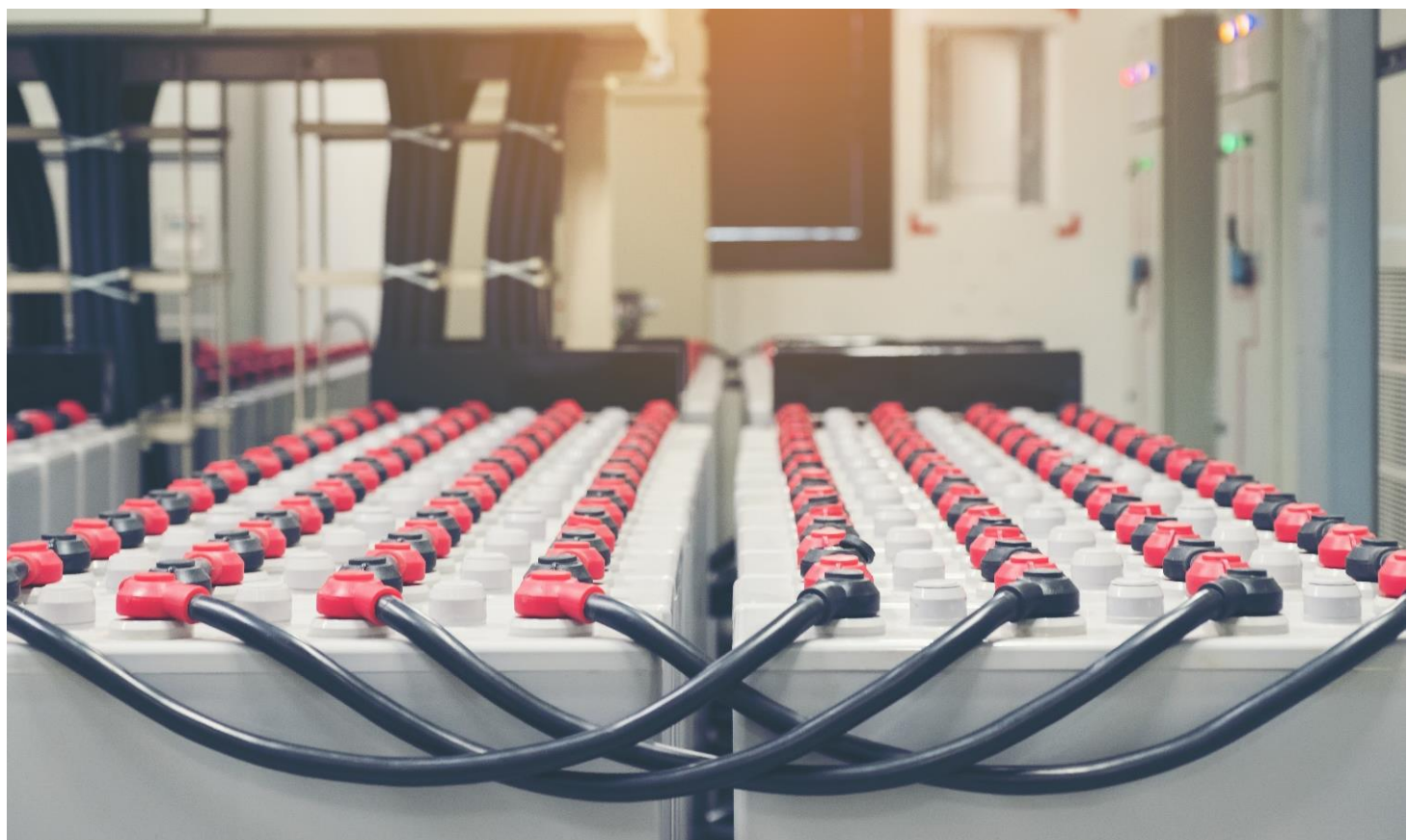
In the context of utility scale energy storage (energy storage)¹ assets, the current electricity market and regulatory framework does not support cash flows of this nature. This creates a significant challenge for private sector investors and financiers to 'bank' storage projects.

Unlike renewable energy projects that generate revenue based on 'output', storage projects can typically generate revenue through:

1. Wholesale energy price trading
2. Payments for providing 'ancillary services'.

These revenue strategies are discussed overleaf.

A number of global and Australian storage projects have relied on government subsidies (eg. Hornsdale Power Reserve), which is not surprising given the nascent state of the energy storage market.



¹ This paper refers only to utility scale energy storage systems. The economics for residential storage systems are different to utility scale storage systems and are not the subject of this paper.

1. Wholesale energy price trading

Wholesale energy price trading is typically a combination of:

1. Time of day / arbitrage trading between **typical** high and low price periods (peak/off-peak)
2. Selling during **unexpected** price spikes (eg. if a generator was to temporarily fail)
3. Buying during unexpected negative pricing, such as during periods of excess generation.

Before each of these strategies are discussed, it is important to understand some of the factors that influence the Australian Energy Market Operator (AEMO). One of AEMO's key roles is to ensure a continuous and instantaneous

supply and demand equilibrium (energy security). While that equilibrium is necessary all the time, the market is currently settled at 30 minute intervals. As demand exceeds supply in a particular market region, the wholesale energy price in that region can rise to incentivise energy discharge into the network (increase supply) or reduction in energy demand (demand response). The opposite will occur when demand falls below supply.

Historically, the highest prices have been in the weekday 'shoulder' periods between approximately 7am-8am and 6pm-9pm. This is typically when demand is high. Despite this pattern, demand and supply in the National Energy Market (NEM)

network is continuously changing, especially with demand management and response, making predicting short run future prices based on historic price trends extremely challenging.

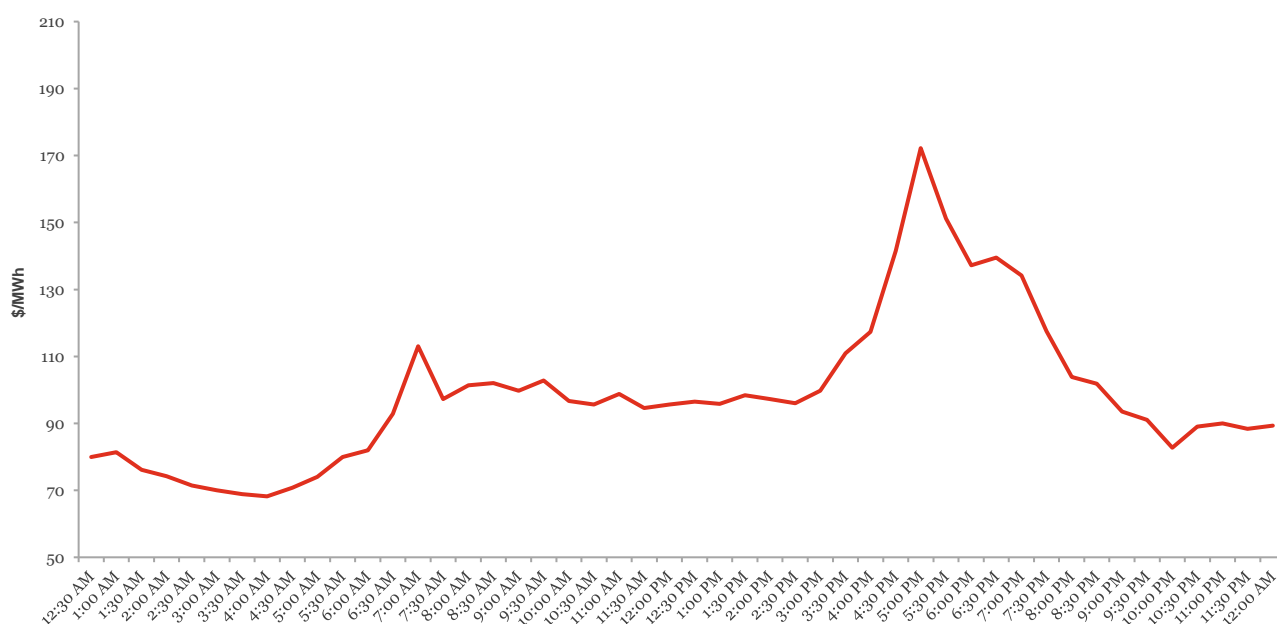
The Australian Energy Market Commission (AEMC) announced in November 2017, that the settlement period for the wholesale electricity spot price will change from thirty minutes to five minutes from 2021. The announcement premised that this change "provides a better price signal for investment in fast response technologies, new generation gas peaker plants and demand response".

Time of day or arbitrage trading

Energy storage projects are able to engage in time-of-day trading strategies; buying low and selling high. To demonstrate the potential of arbitrage pricing,

Figure 1 illustrates the average (unweighted) time of day price in the NEM in 2017.

Figure 1: Total average time of day pricing in the NEM, 2017 (unweighted)



Notwithstanding the ease of identifying high price events in hindsight, projecting the incidence and gravity of future high price events is difficult. This is because the causes of the events are many and varied. Thus, the predictability of the cash flows of a storage project is compromised.

In addition, the capability of energy storage projects to engage

in trading strategies is limited by the storage capacity of the solution, the speed of the solutions' storage/dispatch capability and the existing transmission infrastructure. For example, an energy storage pumped hydro project cannot access the benefits of a high price event unless it has been charged in previous periods. Therefore, even though the market may be experiencing consecutive

high price periods, storage projects may be limited in their ability to dispatch at these times. Similarly, on a hot day, if the energy demand increased, regardless of the potential of the dispatch capability of the storage project, the trading strategy will be limited by how much power the local transmission infrastructure can evacuate in a particular locality.

Price spikes

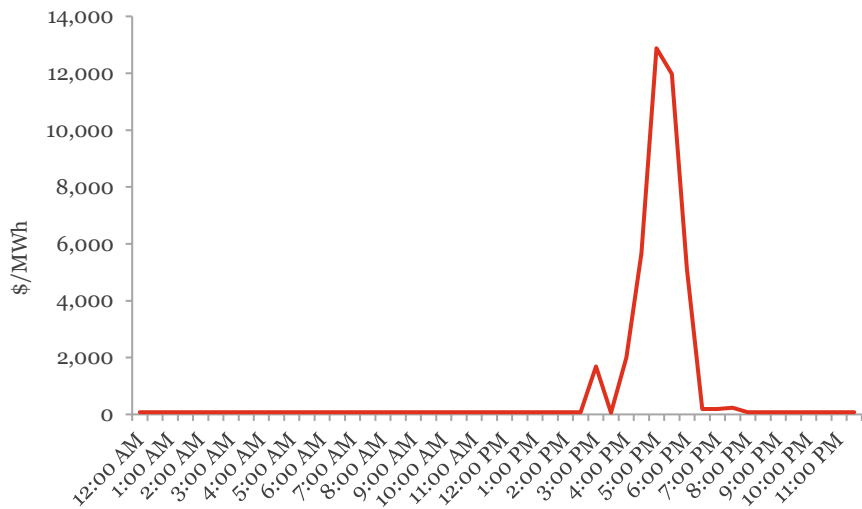
As part of the AEMC's "Reliability Settings", the National Electricity Rules (NER) stipulate a maximum spot price of \$14,500/MWh which is the market price cap.² This price can be reached due to a number of supply, demand or transmission disruptions, eg. when a generation outage occurs. The materiality and location of the outage can have a significant impact on the system's ability to supply power to prevent blackouts. For example, in the early morning of 18 January 2018, as electricity demand began to increase, the generators at Generator A coal plant in Victoria failed and lost 528 MW of generation capacity from the electricity system. During that day, the Victorian wholesale energy price rose from \$86.72/MWh at 3.30pm to \$12,931.04/MWh at 5pm, before falling below \$200/MWh at 7pm. This is illustrated in Figure 2 overleaf.

² From 1 July 2018 to 30 June 2019; reset every financial year.

Figure 2: Generator A failure, 18 January 2018 – wholesale energy price impact

The Generator A outage also contributed to the following

- South Australian wholesale energy prices were also materially impacted, peaking at **\$14,166.50/MWh at 5pm**
- New South Wales and Queensland each experienced a **\$100/MWh increase** to \$234.86 and \$213.93/MWh peak price at 5pm respectively
- Tasmania experienced a **sudden shift to positive pricing** at 5pm following three consecutive negative price intervals (and three more 5.30pm, 6pm and 6.30pm).



Energy storage can help inject power into the grid after an outage which will reduce the amount of energy supply lost and help balance demand and supply.

Large spikes in wholesale energy prices can also produce material cash flows for energy storage projects provided they are optimised to discharge during such periods. However, as wholesale energy price spikes are challenging to predict, combining this with a typical ‘time of day’ trading strategy may result in conflicting priorities. As a result of this unpredictability, it is not possible to include the full revenue from price spike events in financiers’ project cash flows projections.

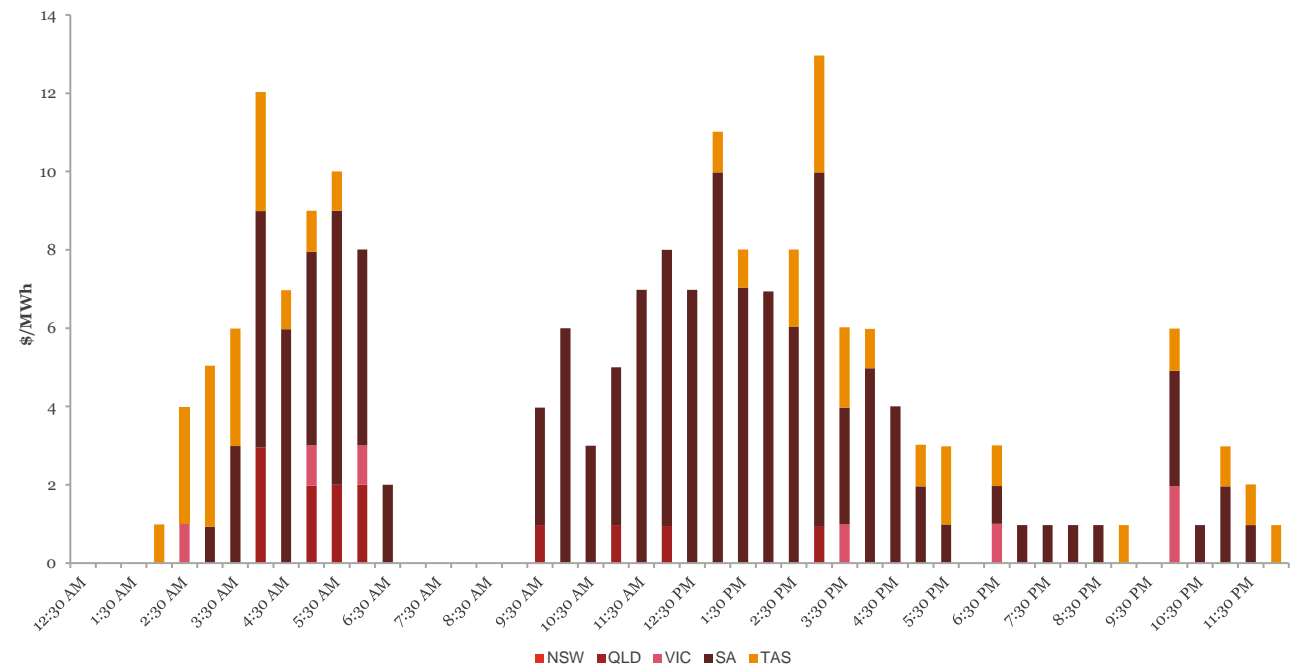
Negative price events

The NER stipulate a minimum spot price of negative \$1,000/MWh which is the market floor price.

Energy storage solutions can earn revenue by consuming energy during these negative price periods. This includes pumping water uphill or charging batteries.

Negative price events have been rare. Throughout 2017 there were only 194 negative price occurrences across the NEM from a total of 87,600 price intervals. Negative price events are usually caused by unexpected decreases in energy demand or increases in energy supply. Figure 3 demonstrates that South Australia and Tasmania were the two largest contributors to the NEM’s negative price events in 2017 and more than 50 per cent of negative price events occurred during daylight hours between 9.30am and 5.30pm.

Figure 3: NEM negative price events (CY2017)



2. Ancillary services payments

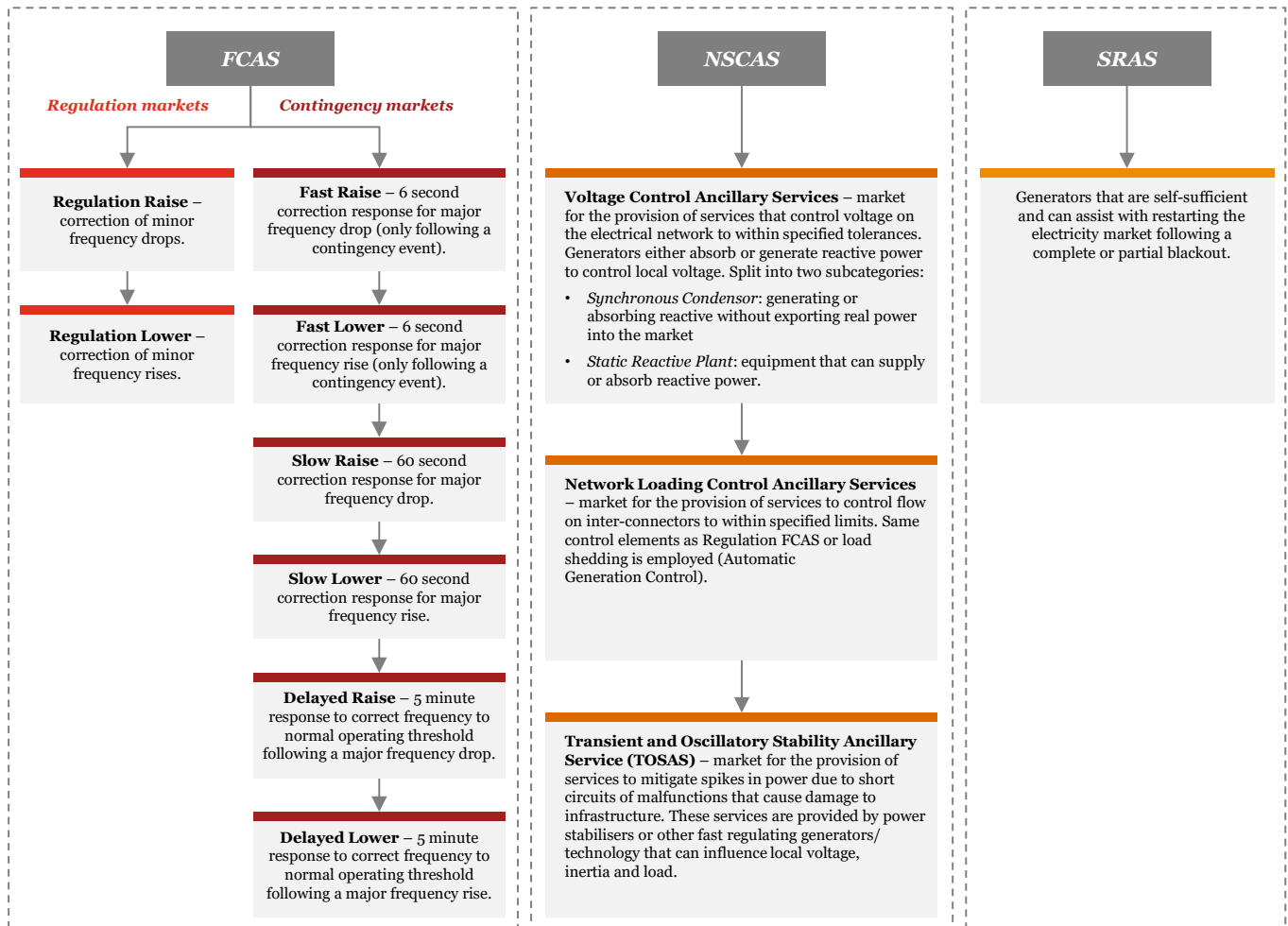
As a general rule every electricity generator may be liable to pay regulated and contingent ancillary services fees. These fees fund the available pool of money to pay the generators that provide ancillary services to the networks. The NEM ancillary services frameworks reward energy providers for assisting with a range of correction services in the network. The three key services include:

Ancillary services framework	Description
Frequency Control Ancillary Services (FCAS)	Aimed at maintaining the frequency of the electrical system at 50 hertz (Hz) (or 50 cycles per second); this is one element of energy security. Energy storage projects can access FCAS through eight potential markets (refer to Figure 4).
Network Support and Control Ancillary Services (NSCAS)	Subdivides into 3 categories to focus on: <ul style="list-style-type: none">• Voltage control within specified tolerances (VCAS)• Flow on inter-connectors to within short term limits (NLCAS)• Control and fast regulation of the network voltage after a fault occurs (TOSAS).
System Restart Ancillary Services (SRAS)	Generators that provide energy to the transmission grid to assist restart following a complete or partial black out.

Source: Guide to Ancillary Services in the National Electricity Market, April 2015 (<https://www.aemo.com.au/-/media/Files/PDF/Guide-to-Ancillary-Services-in-the-National-Electricity-Market.ashx>).

The ancillary services markets have their own pricing mechanisms. The very nature of the market provides for lucrative returns for projects that can participate in each market. However, the market for these services is thin and as additional providers enter, it is likely the profitability within each market could reduce. Figure 4 outlines each market a project can participate in.

Figure 4: Ancillary services markets



Source: AEMO, *Guide to ancillary services in the national electricity market*, April 2015.

Energy storage projects can participate in several ancillary markets by generating or discharging energy into the network when called on by AEMO, or by withdrawing energy from the network when charging. For example, lithium-ion batteries can discharge instantaneously to assist with frequency and voltage controls, while pumped hydro can assist with system restarts.

Three key bankability challenges with energy storage projects participating in ancillary markets are:

1. Ancillary response can require the storage project to charge or discharge creating the possibility of the system operating out of sync with trading strategies
2. The volume of services required to meet the ancillary services is relatively shallow and profitability could be eroded quickly with increased supply
3. The use of storage projects for ancillary support needs to be considered in the maintenance and operability of the hardware. Overuse of storage projects could lead to increased erosion of performance and the need for additional maintenance.

The future of FCAS markets

On 26 July 2018, the AEMC released its *Frequency Control Frameworks Review – Final Report* detailing a number of findings and suggestions to support better frequency control in the long term.³ Increased transparency on FCAS markets was one of the seven key recommendations.

In the report, AEMC concluded that there is a lack of regular and readily available information for FCAS participants about the general performance of FCAS markets. AEMC concluded that increased transparency could assist:

1. Interpretation of the FCAS markets' efficiency and effectiveness
2. Understanding costs and requirements of the system
3. Improve investment and operational decisions.

Through its recommendations, AEMC has identified opportunities for transformation in the way FCAS market information is distributed and accessed to promote performance of the market. The recommendations suggest increased transparency through more detailed and frequent reporting. Internationally, there has been a growing recognition of the increased value energy storage adds to the FCAS market, particularly in a grid with higher intermittent generation. As such, it is expected that the FCAS market will undergo significant reform and transformation both structurally and commercially.

Should the AEMC recommendations be enacted, more detailed energy market information may provide financiers comfort on the future value of FCAS markets and assist investors' due diligence. The AEMC recommendations could provide the information necessary for investors and financiers to better measure the potential performance of energy storage developments in the FCAS markets.



³ Report can be downloaded from: <https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review>

Challenge 2: Positive externalities uncompensated

A storage solution will result in a number of financial and technical benefits to the surrounding network area including reduced risk of curtailment and alleviating pressure on network infrastructure.

The two key financial and technical benefits are the potential:

1. Improvements in loss factors (marginal loss factors (MLF) and distribution loss factors (DLF))
2. Reduction in congestion, allowing projects to increase their export availability into the grid.

Despite these broader benefits there is currently no ability for one project to 'charge' another project for the benefits provided to them, with the exception of costly and timely bespoke bilateral agreements. This 'charge' could be solicited through a regulated return similar to the structure in place for shared energy infrastructure.



This is essentially the “free rider” concept. This creates a significant hurdle to a storage investment by a single project as the opportunity for combined payments from multiple projects to provide economic support for the funding of a storage solution is difficult to practically achieve.

The absence of this compensation limits the economic value of an energy storage project.

What are loss factors?

In general, the *revenue* of a plant is calculated as:

Price x MLF x GO

Price = market price (at the regional reference node)

GO = generation output

MLF = marginal loss factor (or MLF * Distribution Loss Factor; in the case of distribution connections)

Therefore, a change in MLF will result in a direct change to the revenue of a plant. For generators specifically, the allocated loss factor is a function of the generation profile, where having a:

1. Loss factor of one has no impact on a generator's revenue
2. Loss factor less than one signals that network losses will increase as more generation is dispatched at that node, this generally occurs when generation is greater than demand at that node. In this case revenue of the generator will be reduced according to the formula

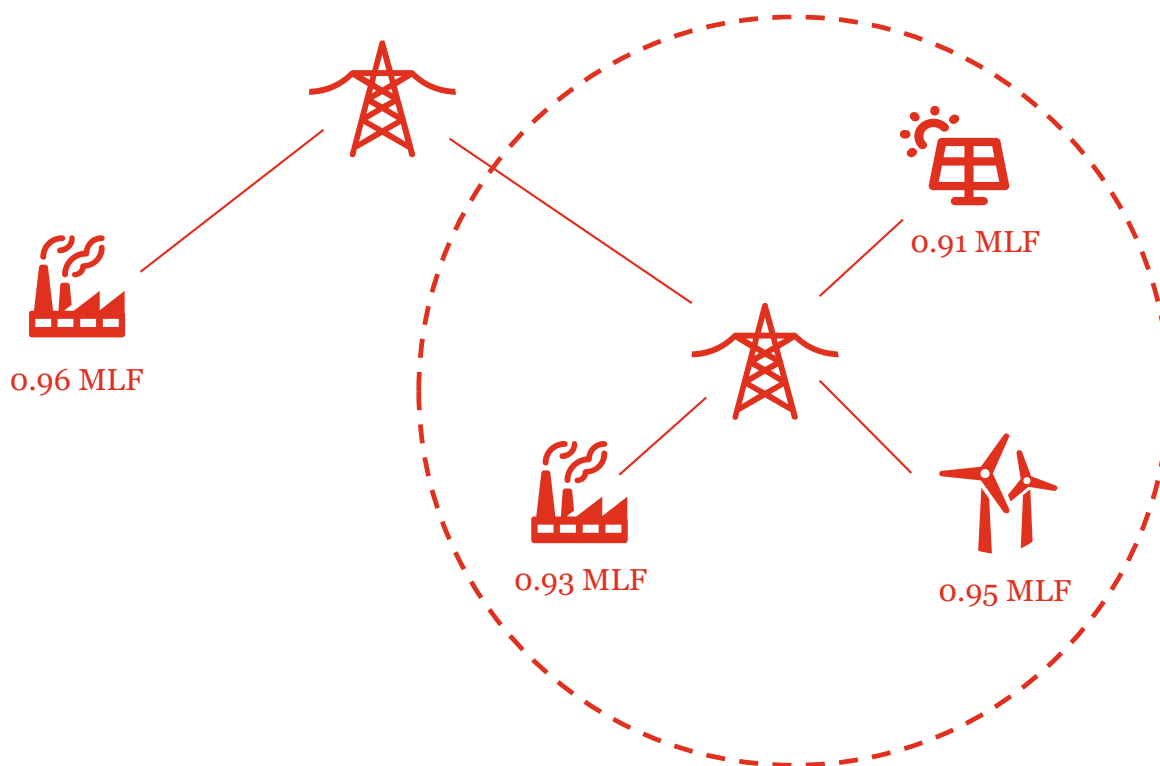
3. Loss factor greater than one signals that network losses will decrease as more generation is dispatched at that node, this generally occurs when generation is less than demand at that node. In this case revenue of the generator will be increased according to the formula.

Due to electricity lines having limited capacity, practically a loss factor will not typically exceed 1.2.

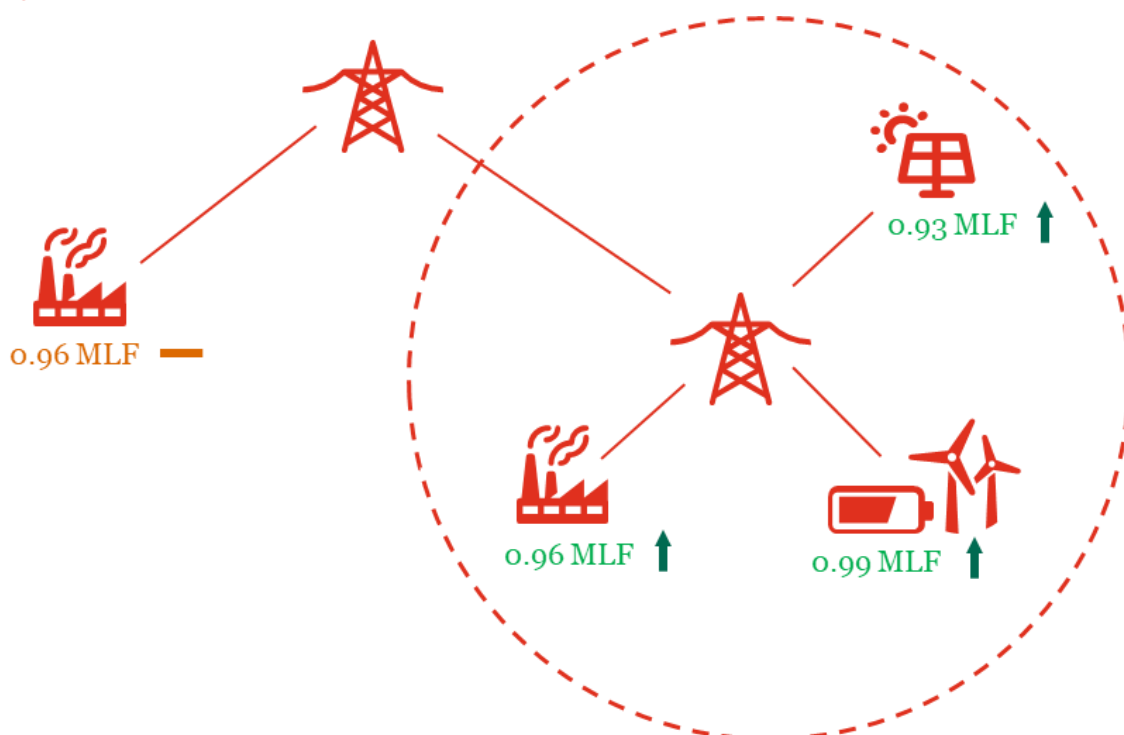


The simplified example below illustrates the potential local benefit of an energy storage project:

Before



After



How is this applicable to energy storage projects?

Energy storage projects can manage both the timing of when energy is supplied into the grid and the rate of dispatch. This essentially creates a smoothing.

Energy storage projects can have two material impacts in relation to network loss factors and requirements for energy curtailment.

1. Project-specific loss factors

Energy storage projects can reallocate energy so that a dispatch profile can be managed. In turn, this should increase the MLF (or DLF) that is allocated to that project. A higher loss factor will generate additional revenue for the project.

the generation profile of neighbouring generators on the local network. By managing the dispatch profile of a project and improving the project-specific loss factor, local generators' loss factors will also be increased.

Neighbouring generators will be free-riders benefitting from a revenue uplift resulting from the presence of a nearby storage project.

In addition, the ability for energy storage projects to manipulate

timing of dispatch could reduce the local network's exposure to curtailment. Curtailment exists when generators are forced to reduce generation to meet network security requirements.

Currently there is no incentive for local generators to contribute to the economic cost of developing a local storage project which can improve local loss factors (and provide revenue upside) and reduce risk of curtailment.

2. Local network loss factors

Loss factor calculations for a specific generator or energy storage project take into account



Additional financial opportunities for energy storage

There are various ways that energy storage benefits the energy network more broadly, as well as supporting the feasibility of new and existing utility scale renewable energy generation assets. Below are four (4) value accretive opportunities of energy storage assets.



Power purchase agreements

Energy storage projects can also support renewable energy generation projects with the procurement of power purchase agreements (PPAs). The energy storage can assist by providing a potential 'firm' energy supply to a purchaser.

Retailer renewable energy “run of plant” PPAs are scarce in the market. This leads to an increased focus on the high energy C&I consumers to underwrite new renewable energy generators with long term corporate PPAs. Energy storage developments can help better align generation and demand profiles for consumers and avoid having to pay risk premiums to a third party provider of ‘firming’ services. This will alleviate pressure in the market and promote development as Australia strives towards a cleaner future.



Grid augmentation

The pressure on transmission and distribution networks can be alleviated by energy storage's ability to redistribute energy. This in turn has the potential to defer and/or minimise necessity for network upgrades, the cost of which are, for the most part, passed through to users and subsequently consumers.

As a result, there may be financing opportunities that align with deferred or substituted capital benefits for network service providers.



Energy management

By minimising electricity purchases during peak electricity-consumption hours when time-of-use (TOU) rates are highest and shifting these purchase to periods of lower rates, behind-the-meter customers can use energy storage systems to reduce their bill.



Renewables integration

Minimising export of electricity generated by behind the meter photovoltaic (PV) systems to maximize the financial benefit of solar PV in areas with utility rate structures that are unfavourable to distributed PV (eg. non-export tariffs).

Development of alternative financing models

As at September 2018, there are 55 large-scale energy storage projects in Australia that are existing, under construction, planned or proposed.⁴ Together, these projects will have a total capacity of over 4 GWh.

While financing costs remain a challenge without incentives, there are currently three key proponents:

- Developers of large-scale renewable energy projects seeking to co-locate battery storage onsite (whilst the projects are privately owned, the battery development is often supported by State Government or ARENA grant funding)
- Public private partnerships for standalone storage systems such as the Hornsdale Power Reserve
- Regulated transmission and distribution service providers pursuing storage solutions behind and in front of the meter to manage peak demand and defer network investment.

The increased interest and public need for these projects is paving the way for new financing models.

Box 1. Case study of ESCRI-SA Dalrymple battery

The ESCRI-SA Dalrymple 30MW battery project illustrates a potential commercial model for large scale energy storage systems which provides both regulated and unregulated revenue streams to the transmission network service provider (TNSP).

Co-located with AGL's 91MW Wattle Point Wind Farm, the battery is designed to provide back-up power in the event of any interruption to supply from the grid until the grid is restored. Its purpose is to strengthen the grid and improve reliability for the lower Yorke Peninsula in South Australia.

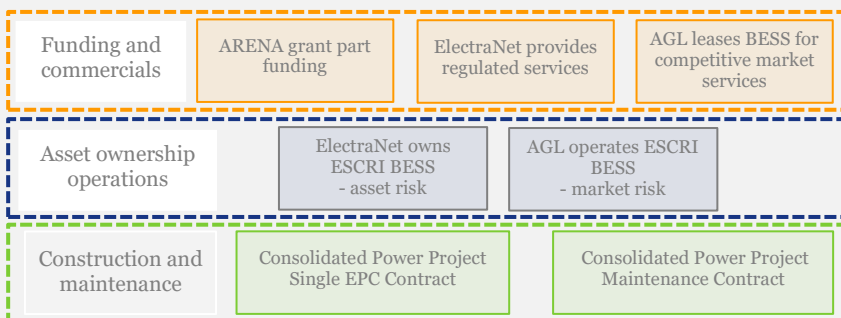
The Dalrymple battery will be designed, owned and built by ElectraNet (TNSP in South Australia). The battery will provide both regulated network services and unregulated competitive market services.

Regulated network service benefits include:

- improved reliability for the southern Yorke Peninsula region by supplying power for approximately 2 hours following the loss of transmission supply, or longer if there is sufficient renewable generation from Wattle Point wind farm and/or local PV
- supply of fast frequency response (FFR) to reduce Heywood interconnector constraints and improve power system security by quickly injecting power into the grid following a disturbance.

ElectraNet will earn unregulated revenue in relation to the lease payments from AGL. AGL will operate the asset with market trading through the provision of market caps (a derivative/ insurance product) and FCAS services.

Figure 5: Commercial arrangements for the Dalrymple battery



Source: www.escri-sa.com.au/globalassets/reports/escri-sa-project-summary-report-the-journey-to-financial-close-may-2018.pdf

⁴ Smart Energy Council report on large scale energy storage excludes pumped hydro, https://www.smartenergy.org.au/sites/default/files/uploaded-content/field_f_content_file/australian_energy_storage_market_analysis_report_sep18_final_o.pdf?_ga=2.180176672.568819707.1548122416-1192601723.1543458004_Sep-2018

Key takeaways

Private sector adoption of energy storage has been limited due to a combination of high capital requirements and the barriers to financing discussed above.

The challenges have been acknowledged by many stakeholders with early regulatory changes underway, including the transition to 5-minute trading intervals, AEMC's recommended transformation of FCAS markets and supportive government policy at the state and federal level.

Despite the challenges, the benefits of network storage remain clear. Early adoption and trials of grid-connected storage projects, such as the Hornsdale Power Reserve, have showcased the ability to trade in the wholesale markets and also provide ancillary services and stability to local networks for the benefit of the community.

Acknowledging the challenges, the obvious questions remains – what must change to encourage investment into these key energy storage assets?

There are many paths to solving this question, including reforming the markets that energy storage assets operate in to help promote private sector financing through creating certainty in forecasting cash flows.

Ownership of energy storage by NSPs or the development of unregulated services are alternate paths. To manage these ownership options, regulatory reforms will need to be introduced to properly facilitate the developments.



For more information or to discuss the future financing of energy storage in Australia, please contact one of our contributors to this paper.



Chris McLean
Partner
Infrastructure Lead Advisory
E: chris.mclean@pwc.com
T: +61 (2) 8266 1839



Sally Torgoman
Managing Director
Infrastructure Lead Advisory
E: sally.torgoman@pwc.com
T: +61 (2) 8266 6056



Danny Touma
Director
Infrastructure Lead Advisory
E: danny.touma@pwc.com
T: +61 (2) 8266 1719



Martin Ivanovski
Associate Director
Infrastructure Lead Advisory
E: martin.ivanovski@pwc.com
T: +61 (3) 8603 2483



Sophie de Lima
Manager
Infrastructure Lead Advisory
E: sophie.de.lima@pwc.com
T: +61 (2) 8266 0681



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