Batteries and electricity network service providers in Australia: regulatory implications

A report for the Public Interest Advocacy Centre (PIAC)

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Executive Summary

One of the first things that any student of electricity economics learns is that electricity is not storable in meaningful quantities. This characteristic, in the context of peak electrical demands much higher than average demands, has meant that large amounts of capacity in generation, transmission and distribution are infrequently used.

This appears to be changing. There have been rapid developments in battery storage that might mean that batteries that are able to store reasonably large amounts of electricity become ubiquitous. This raises many interesting and important issues for producers and consumers.

One significant regulatory issue is whether regulated electricity network service providers should own and operate batteries connected to the shared grid or behind the customers' meters, and if not how the benefits that batteries offer to the shared grid, are to be realised. The Public Interest Advocacy Centre, supported by the Brotherhood of Saint Laurence, the Australian Conservation Foundation and Energy Consumers Australia has commissioned this report to explore this question.

Australia's economic regulators and market operators are currently actively considering the issues that are the subject of this report. In the context of extraordinarily rapid technology and business development, this report seeks to provide broad coverage of the relevant issues and to recommend arrangements that are in consumers' interest. We expect that the issues of this report will continue to be studied and debated in much further detail and so this report purports to be no more than an early contribution to the discussion, focused particularly on consumers' interests.

Batteries in context

Electrical storage can be classified as mechanical, electrochemical (battery), electric, thermal and chemical. There is rapid technology development in each of these areas, but mechanical, and particularly pumped hydro[1] storage accounts for 98% of all electrical storage internationally. Batteries account for around 600 MW of grid-scale storage globally. This is a tiny proportion of global electrical demand (0.01%) but it is growing rapidly. Lithium-ion batteries in particular have favourable cost, size and operational characteristics which has meant that they have dominated the growth of grid-scale storage.

Battery economics

Batteries can provide valuable services in storing electricity when it is inexpensive and reproducing it when it is more valuable. Batteries can also substitute for transmission network augmentations, and can provide other services that are valuable in the operation of a power system. Participants - end users, retailers and energy market participants and regulated network service providers – will value different aspects of batteries, for example the peak capacity, the volume they can store, their discharge and recharge rates and their optimum operating cycles.

Battery economics is conceptually straight-forward but complex in practice because it depends on many uncertain factors. There is an abundance of market growth projections by analysts, investment banks and market operators. The dominant consensus is that the market for battery storage behind-the-meter and on the shared grid will grow rapidly.

Framing the debate

The electricity industry in Australia, like that in much of the developed world, has separated the networks from the production of electricity. This separation was decided in full recognition that networks can substitute or complement generation. This reflects a belief that the benefits from wholesale and retail competition exceed the disbenefits of integration that might otherwise be achieved through joint ownership and control.

[1] Where electricity is used to pump water to an upstream reservoir and the water left to flow back down through turbines to produce electricity when needed

Pumped hydro storage is invariably treated as a form of generation and so firms that own and operate networks are prevented from owning and operating pumped hydro. A key question is, therefore, whether network service providers should be prevented from owning and operating batteries in their regulated business, for the same reason.

We identify arguments for and against this proposition. Electricity prices are unlikely to ever be sufficiently reflective of their true locational and temporal value to provide an appropriate market signal of where it would be efficient to locate storage. This suggests that ownership and operation of storage by network service providers may be helpful. In addition, there are some characteristics of battery storage (flexibility, transportability, scalability, low environmental impact at point of use) that might mean batteries are likely to be even more valuable to network service providers than pumped hydro. Again this suggests that if network service providers are prevented from owning batteries, and as a consequence they are not developed, consumers would be worse off.

However, there are also compelling arguments for preventing network service providers from owning batteries in their regulated businesses. These arguments include that battery development, at scale, can have a significant impact on wholesale markets. In addition, the track record in Australia of the effectiveness of regulation in protecting consumers from the abuse of monopoly power is not encouraging.

Experience elsewhere

Other countries are also considering how to regulate network service provider involvement in batteries.

In California, the State Government has set mandatory storage development targets and requires that not more than half of the target can be included in the regulated asset base. The target does not specify storage technology but does specify the amount to be connected to transmission and distribution networks and the amount to be connected "behind-the-meter".

In Britain, we are not yet aware of regulatory or policy development. However several battery development projects have been funded through the "low carbon networks fund", and this has included work on regulatory models. In Scotland, one of the distributors has secured the development of a grid-scale battery and purchases the services of the battery through a "congestion management contract".

In New York State, a far reaching reform of the electricity sector is underway to separate the planning and operation of electricity distribution networks. The arrangements for battery storage are not the primary driver of this reform, but rather are seen as part of the context of demand-side developments (including distributed renewable generation, smart metering, demand-side response) that, in their view, justify the fundamental changes.

Options

We identify seven possible options for network service provider involvement in batteries, summarized in Figure E1. They cover the spectrum from NSPs having a full monopoly over the development of grid-connected batteries to Option 7 where NSPs are prevented from including grid-connected batteries in their regulated asset bases.

Figure E1. Options for NSP involvement in grid-connected battery storage

NSP complete monopoly ⟷ NSP competes with others in unregulated market

Option	1	2	3	4	5	6	7
Description	NSP Monopoly	Inclusion in RAB but not Monopoly	Ceiling on inclusion in RAB	Ceiling and network benefit only inclusion in RAB	Technology agnostic procurement	No RAB inclusion	Split operation from ownership
NSP Monopoly	Yes	No	No	No	No	No	No
Inclusion in NSP RAB	Full	Full	Full	Partial	None	None	None
Third Party Involvement	No	Maybe	Yes	Maybe	Yes	Yes	Yes

Recommendations

NSPs should be allowed to develop unregulated businesses for provision of grid-connected and behind-the-meter storage. But in preparation for this it would be valuable to carefully examine the arrangements for ring-fencing of regulated activities from unregulated activities and, where applicable, the arrangements for ring-fencing networks from retail activities. It would also be valuable to examine the nature of the relation that network service providers have with end users to ensure that by virtue of this relationship they are not able to obtain an unfair competitive advantage in the development of grid-connected and behind-the-meter batteries.

We suggest that Options 1,2 and 3 be rejected and Options 4 (and a variant thereof), 5 and 6 should be subject to further detailed examination. We think Option 7 is the most comprehensive and thoughtful approach to the issue. However serious consideration of this option in regulatory fora is not plausible in the absence of political commitment to the profound reorientation of the industry that this option entails.

We also suggest that NSPs be barred from the ownership of batteries that are located behind the customer's meter. Most importantly, in the context of very rapid technology development, we suggest that regulatory arrangements for NSP involvement in batteries must be adaptable to change and this should be an important of the consideration of all options.

Next steps

This report has sought to cover extensive ground in an area of very rapid technology and commercial development. While the rate of growth of the battery market is uncertain it would be valuable to the industry and consumers that clear regulatory arrangements for network service provider involvement are developed before the industry develops. Much more work will need to be done to decide these arrangements..

Abbreviations

Abbreviation	Meaning
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
BNEF	Bloomberg New Energy Finance
BOS	Balance of System
CAES	Compressed Air Energy Storage
CPUC	California Public Utilities Commission
CSP	Concentrated Solar Power
DER	Distributed Energy Sources
DNO	Distribution Network Operator
DSO	Distribution System Operator
ETIP	Energy Technology Innovation Policy
FES	Future Energy Solutions
FERC	Federal Energy Regulatory Commission
FiT	Feed-in Tariff
IMO	Independent Market Operator
LCOE	Levelised Cost of Energy
LSE	Load Serving Entity
NEM	National Electricity Market
NMC	Nickel Manganese Cobalt Oxide
NSP	Network Service Provider
NYPSC	New York Public Services Commission
PHS	Pumped Hydro Storage
PPA	Power Purchase Agreement
PV	Photovoltaic
RAB	Regulatory Asset Base
REV	Reforming the Energy Vision
SMES	Superconducting Magnetic Energy Storage
SNG	Synthetic Natural Gas
SSEPD	Scottish and Southern Energy Power Distribution
SWIS	South Western Interconnected System

UKPN	UK Power Network
VRB	Vanadium Redox Battery

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1 Introduction

Until recently, one of the first things that any student of electricity economics will have learned is that electricity is not storable in meaningful quantities. This characteristic, in the context of peak electrical demands often much higher than average demands, has meant that large amounts of capacity in generation, transmission and distribution were infrequently used.

This may be changing. There have been rapid developments in battery storage that might mean that batteries that are able to store reasonably large amounts of electricity become ubiquitous, whether installed at customers' premises ("behind the meter") or connected to the grid. Batteries of smaller capacity are now common in laptops, telephones and domestic appliances and are now spreading to private transport (electric cars).

Rapid advances in battery technology are occurring as a result of this demand-side proliferation and now also as a result of increasing electrification of personal transport. There are a range of views on the rate at which large scale batteries will be useful in consumers and in grid scale storage. Many think significant market penetration is imminent, particularly in Australia, with its significant and growing solar penetration.

The proliferation of larger scale batteries has the potential to radically change the economics of electricity supply. Large capacity surpluses in generation and transmission will no longer be needed to meet rare peak demands. Differences in the price of electricity at different times of the day and year are likely to narrow. Many consumers may find it more economical to produce and store their own electricity and progressively migrate away from grid supply. Newly connecting renewable generators might integrate with batteries and other forms of storage, delivering more constant and predictable production.

These issues are now being actively discussed in Australia and internationally. There is a flourishing of product and service development. Innovators are actively looking for ways to produce and store electricity, and ways to manage customer demands and integrate products and solutions so that the whole is more than the sum of its parts.

Retailers and other market participants are trying different business models and positioning themselves to meet changing demands.

From the perspective of the design and operation of an electrical power system, batteries have many advantages. Unlike almost all other types of electricity generation, their full capacity can be called upon almost instantaneously, and many types of battery can switch very rapidly between producing and consuming. Unlike diesel generators, they produce no air and little noise pollution at the point of use. Also unlike engines they do not require separate fuel supply. Batteries can easily be relocated and connected into power systems and modern battery systems can have a small footprint. Being highly responsive and controllable, from a power system planner and network operators' perspective they are desirable.

Distribution network service providers are therefore interested in the potential for the integration of battery storage in their operations. Several trials are under-way in Australia and in other countries to understand this potential.

Batteries also offer opportunities to market participants and consumers. Households and businesses that install batteries will be able to take advantage of differences in the price of electricity by buying when prices are low and using the stored electricity to supply themselves, thus avoiding higher prices. This advantage will be even greater for those households with rooftop solar who can use the battery to store solar electricity that would otherwise be sold to the grid at prices typically around a quarter of the price that households pay to buy from the grid. Some households and businesses are looking to batteries as an option that might allow them to completely disconnect from the grid.

Batteries also present advantages to communities and groups of energy consumers who might choose to have their own battery or share access to a larger battery. In combination with localised generation sources, batteries can allow communities to form their own isolated grids. There seems to be considerable and increasing interest in this by regional communities and effected housing estate developers.

At times, the interest of some or all effected parties will align. For example, a wise investment in a battery by a network service provider will reduce the need for more expensive network augmentation. Network service providers (NSPs) gain from the investment by achieving a return on their outlays. Consumers and producers also benefit from a network that costs less than it otherwise would.

But the parties may also have competing interests. For example, a network service provider that installs batteries can affect the demand and supply for electricity, thus affecting wholesale prices. This affects the businesses of retailers and generators who, depending on their trading positions, can gain or lose from this. If network service providers do not spend wisely on batteries, and if they are allowed to include such expenditures in their regulated asset base, consumers will pay for assets that are not useful.

Network service providers have an incentive to protect their business from declining use and therefore have an incentive to undermine consumers' ability to reduce their dependence on the grid and ultimately to disconnect from the grid. By investing in batteries that they own and operate, they can crowd others out from investing in batteries and therefore continue to tie those customers to the grid.

In this context, the Public Interest Advocacy Centre has commissioned this report to consider whether regulated network service providers (NSPs) should be allowed to include batteries in their regulated asset base, and thereby recover the cost of such batteries through regulated charges spread across the entire customer base. The paper also considers a number of subsidiary regulatory design issues.

The paper is set out as follows:

- Section 2 surveys electrical storage technologies to establish a taxonomy that can help to place batteries in the context of available and possible future alternatives.
- Section 3 surveys the economics and business models for batteries from the perspective end users that might choose to own and operate their own battery, from the perspective of market participants in the provision of batteries and battery service and from the perspective of regulated network service providers.
- Section 4 presents a conceptual discussion of whether distributors should be allowed to own and operate grid-connected batteries.

- Section 5 examines the approach to the regulation of batteries in California, Great Britain and New York State.
- Section 6 constructs and evaluates various options.
- Section 7 makes recommendations.

2 Battery storage in context

This section describes battery storage in the broader context of the range of possible ways energy can be stored. It starts by describing why storage is valuable in electrical power systems for end-users, energy market participants, network service providers and power system operators. It then outlines the range of storage technologies classified as mechanical, electrochemical, electric, thermal and chemical. The section concludes with a focus on battery storage, particularly the increasing use of lithium ion for demand-side and supply-side applications.

There is an extensive literature on the taxonomy of battery storage characteristics and technologies. We found CSIRO (2015), AECOM (2015) and International Energy Agency (2014) particularly useful.

2.1 Why storage may be valuable

For end users, storage provides the opportunity to store electricity when it is relatively inexpensive and then to use or sell it later when it is more valuable.

Energy market participants can use storage in the same way. For them, batteries can also diversify risk. It may also provide the opportunity to profit from the installation and sale of batteries, and facilitate the provision of services in future distributed electricity markets (both grid-connected and off-grid customers).

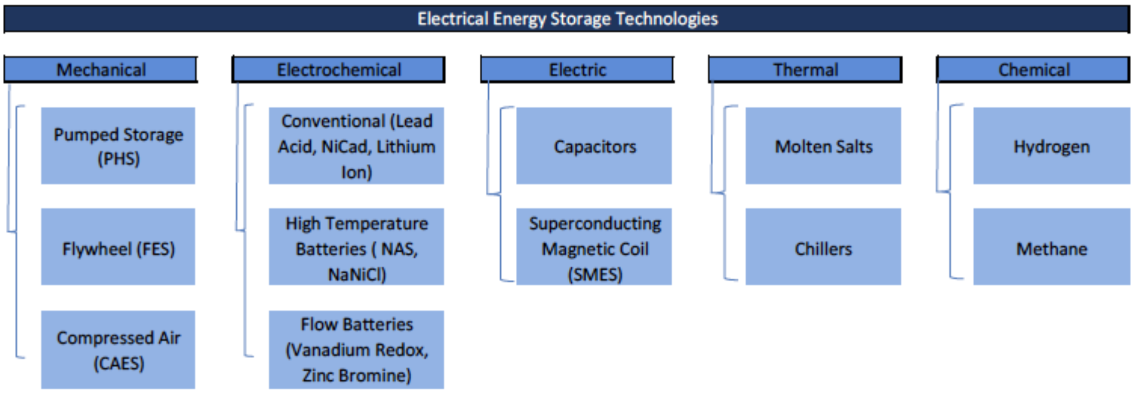
For NSPs, storage provides a way to defer or avoid major grid augmentation by shifting demand from one time to another and thus creating spare capacity when most needed.

Storage can also be valuable to power system operators in electrical power systems by helping to rapidly increase or decrease production to help to stabilise the system frequency. It can help to smooth out the large oscillations in customer demands and thereby present a much more reliable supply. Storage can also help to start a power system whose main generators have shut down or become disconnected from the shared power system.. This is known as “black start”.

2.2 Grid-scale electrical storage technologies

Deutsche Bank (2015) describe grid-scale electrical storage technologies in five categories: Mechanical, Electrochemical, Electric, Thermal and Chemical, as shown in Figure 2. We outline the technology description, the worldwide and Australian operational storage capacities throughout this section.[2]

Figure 2. Electrical energy storage technologies



Source: Deutsche Bank (2015)

2.2.1 Mechanical

The three primary mechanical storage systems are Pumped Hydro Storage (PHS), Flywheel Energy Storage (FES) and Compressed Air Storage (CAES).

PHS is designed with two vertically separated water reservoirs. Water is pumped from the low to the high reservoir when wholesale prices are low and left to flow down to the low reservoir when prices are higher. PHS is the most mature large scale grid-connected technology and makes up 98% of total world storage capacity (142 GW). Australia has three operational PHS plants, Shoalhaven (240 MW), Wivenhoe (500 MW), and Tumut 3 (600 MW) with 1,340 MW of capacity, built over 30 years ago.

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[2] The worldwide and Australian operational capacities are sourced from the U.S. Department of Energy (2015) database – accessed 16 Aug 2015 – based on 'commissioned' date and 'operational' status

FES uses a rotating body/cylinder in a compartment with bearings and a transmission device. The energy is maintained in the flywheel by keeping the rotating body at a constant speed. The flywheel is accelerated by drawing power from the grid and can be feed-back as it decelerates. Flywheels are effective for power system rapid response applications such as frequency regulation. The total worldwide capacity is 920 MW (CME analysis from US DOE database). Australia has two operational flywheels in Western Australia with 1 MW of total capacity.

CAES uses electricity to compress air, which is typically stored in an underground cavity. Electricity is released when the compressed air is mixed with natural gas, which is burned and expanded in a modified gas turbine. There are five operational CAES projects worldwide with a total capacity of 435 MW. There are no CAES installations in Australia.

2.2.2 Electrochemical

Electrochemical storage, which is typically referred to as battery storage, use chemical reactions between two or more electrochemical cells to enable the flow of electrons thereby creating an electrical current. A battery consists of two electrodes, a positive electrode (cathode) and a negative electrode (anode). In between these electrodes is a layer of electrolyte. This can be a liquid, gel or solid material. The choice of chemical compounds used for the electrolyte and electrodes determines the nature of the battery device, the redox reaction[3], cell voltages, energy storage and power capability.

The most common battery technologies are Lead Acid, Lithium Ion, Flow Batteries and Sodium-based. There is over 600 MW of commissioned grid-connected battery storage worldwide. Australia's operational grid-connected battery storage capacity is currently 5.7 MW.

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[3] An oxidation-reduction (redox) reaction is a type of chemical reaction that involves a transfer of electrons between two chemical compounds

2.2.3 Electric

Capacitors and Superconducting Magnetic Coil (SMES) are two possible electrical storage technologies.

Capacitors are passive electronic components that store energy in an electrostatic field. A capacitor consists of two conducting plates separated by an insulating material. In an SMES system, the energy is stored in a magnetic field created by the flow of direct current in a superconducting coil, kept below its superconducting critical temperature. The main component of this system is a coil made of superconducting material. Worldwide there are 22 MW of installed grid-connected electrical capacity and no operational grid-connected electric storage technologies in Australia.

2.2.4 Thermal

Thermal storage technologies described in this section include molten salts and chillers.

Thermal storage uses materials that change their phases (solid to liquid and vice versa) to store and release energy. Molten salts have been used for concentrated solar power (CSP) plants such as the Crescent Dunes plant (110 MW with 10 hours of storage). Salt is heated by solar radiation and then transported, in a molten state, to a hot salt storage tank. Electricity is produced when the hot salt passes through a steam turbine. Globally, there is 1.34 GW of molten salt thermal storage operational, mostly in Spain and the U.S. Australia has no operational grid-connected CSP plants.

Another form of thermal storage is to freeze water, consisting of a charging system and a thermal storage tank connected to a building's air-conditioning system. During the evening off-peak periods, the charging system freezes water which is stored in the thermal storage tank. During day-time peak air-conditioning periods, the ice is used to cool the hot refrigerant as opposed to the air-conditioner compressor. The total world capacity of these ice chillers is 192 MW, mostly in Northern America. Australia has no operational chiller capacity.

2.2.5 Chemical

Chemical storage technologies include the production and subsequent combustion or fuel-cell conversion of hydrogen or methane to produce electricity.

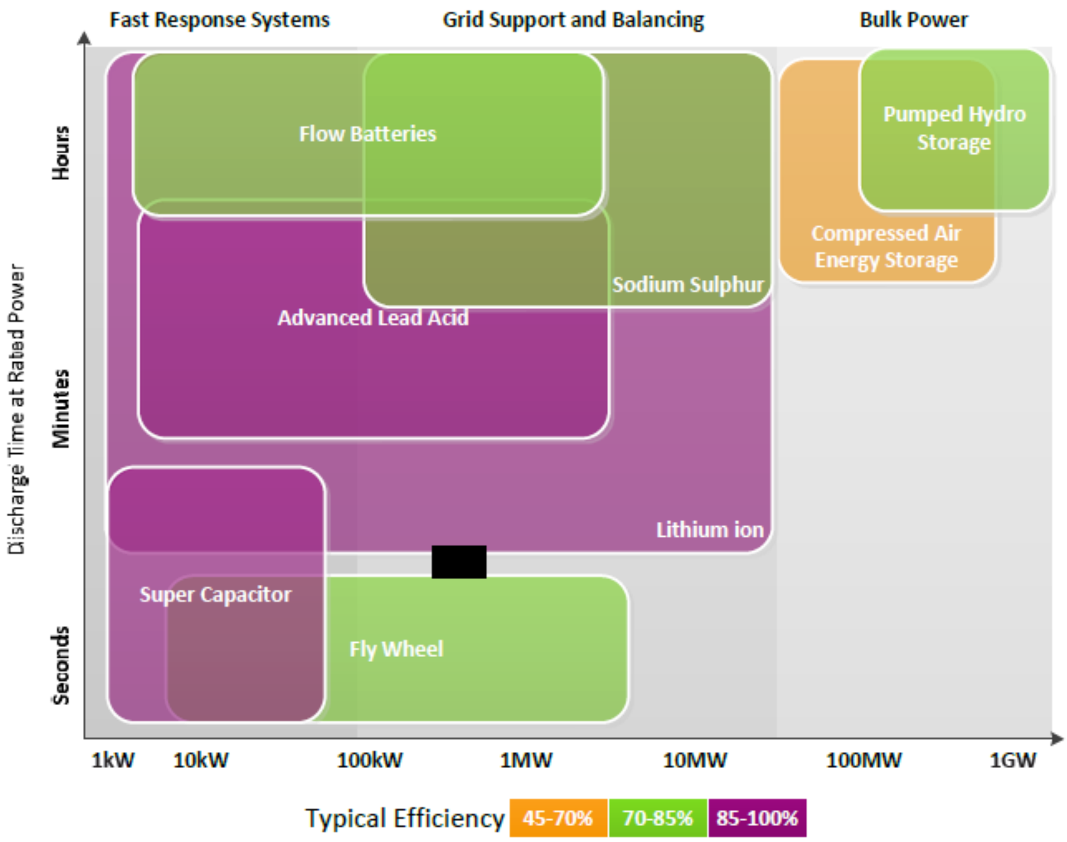
A hydrogen system consists of an electrolyser, a hydrogen storage tank and a fuel cell. The electrolyser splits water with electrical input into its constituent elements of hydrogen and oxygen. When electrical output is required, the hydrogen is processed through the fuel cell with oxygen (a reversal of the electrolyser process) to generate electricity and water. Worldwide there are 3 MW of grid-connected hydrogen storage, all in Germany and France.

Another application of hydrogen storage is using a synthesis of methane (SNG) to store electricity as chemical energy. After hydrogen is created through the water-splitting process, a further step involves the mixing of hydrogen and carbon dioxide to methane within a methanation reactor. The resultant methane can be used in a gas turbine for electricity generation. There are no grid-connected electrical methane storage plants worldwide.

2.2.6 Storage technology properties expressed as discharge and power

Storage technologies can be distinguished based on their discharge times, rated power and typical efficiencies as shown in Figure 3. PHS has a high power capacity and can be discharged over a long time period. This compares with capacitors (shown on the chart as 'Super Capacitor') and fly wheels which have a lower power capacity but operate very quickly over a short time. Batteries (shown in Figure 3 as 'Flow Batteries', 'Sodium Sulphur', 'Advanced Lead Acid' and 'Lithium ion') are modular and scalable which can provide short to medium term storage capability for slow and fast discharge rates.

Figure 3. Energy storage technologies by rated power, discharge time and typical efficiency



Source: AECOM (2015)

2.3 Battery storage

This section presents the most prevalent battery storage technologies, Lead Acid, Lithium Ion, Flow Batteries and Sodium-based batteries. We describe the battery technologies, the worldwide and Australian operational grid-connected capacity[4].

2.3.1 Lead acid batteries

Lead acid batteries are the most mature battery chemistry and have been in use for over 150 years since 1859 (Lead-Acid Battery Info (2015). Lead acid batteries have evolved from using a liquid electrolyte to a gel, allowing the battery be used in different

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[4] Ibid.

positions without leakage. Further evolution to the valve-regulated lead acid battery (also called 'sealed') was developed using modern absorbed glass mat types[5] allowing operation in any position. Worldwide there are 132 MW of grid connected lead acid batteries currently operational.

There are two operational projects in Australia, a 3MW / 1.6 MWh King Island lead-acid battery installed by the Tasmanian generation business, Hydro Tasmania for storing excess PV and wind and reducing diesel generator use.[6] The other project is a 1MW / 0.5 MWh storage system at the Hampton wind park for ramp rate control of wind generation[7]. Most of Australia's existing off-grid systems use lead-acid batteries.

2.3.2 Lithium-ion Batteries

Lithium ion (Li-ion) batteries involve the movement of lithium ions between a porous carbon anode and a Lithium oxide cathode. The two most prominent Li-ion technologies are lithium iron phosphate ($LiFePO_4$) and lithium nickel manganese cobalt oxide (NMC). Globally, there is 340 MW of grid-connected lithium ion battery storage.

Australia has 1.35 MW of grid-connected lithium ion storage operational (the Victoria Ausnet Services' 1 MW / 1 MWh grid storage). There are another 2.9 MW under construction, the largest being Powercor's 2 MW for transmission support, ancillary services and peak capacity.

2.3.3 Flow Batteries

Flow batteries consists of two storage tanks filled with electrolyte separated by a proton exchange which allows the flow of electrons and hydrogen ions. The chemical

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[5] Absorbed glass mat (AGM) batteries differ from flooded lead acid batteries in that the electrolyte is held in glass mats, as opposed to freely flooding the plates, improving charge times, reliability and portability

[6] Hydro Tasmania (2015)

[7] Ecoult (2015)

composition of the electrolyte solution defines the sub-categories, the most notable are Vanadium Redox Battery (VRB) and zinc-bromine. Globally, the total grid-connected capacity of flow batteries is 36 MW.

During the 2000s, there were 690kW of flow battery storage projects operational in Australia, all of which are now decommissioned. There are some flow battery companies such the Brisbane-based 'Redflow' who offer flow battery storage for households.[8]

2.3.4 Sodium-based batteries

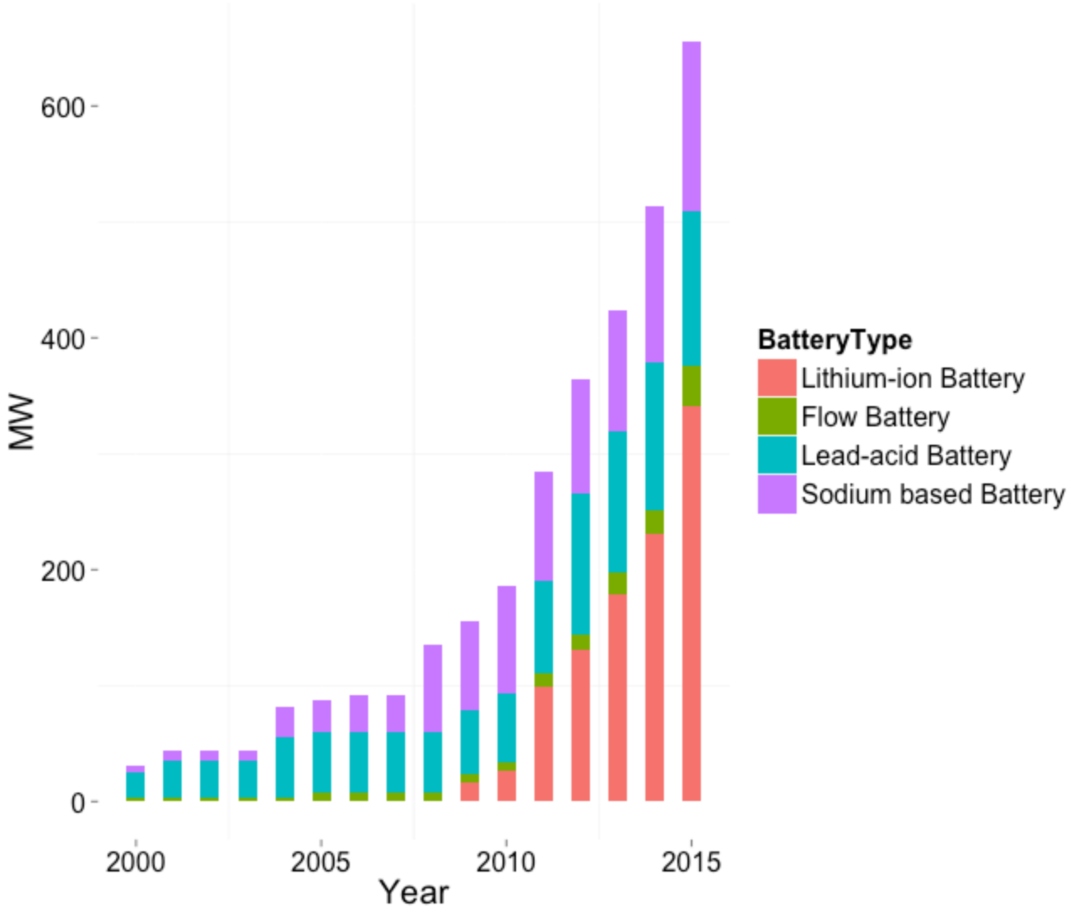
Sodium-based batteries consist of molten sulphur at the cathode and sodium at the anode, which are separated by an electrolyte. The global sodium-based battery operational capacity is 147 MW. There are no operational grid-connected sodium-based battery storage installations in Australia.

2.3.5 The growth of batteries

The capacity of grid-connected battery storage has increased rapidly, from 31 MW in 2000 to over 600 MW in 2015, the majority of which is made up of Lithium ion batteries as shown in Figure 4.

[8] Vorrath (2015b)

Figure 4. Cumulative global capacity (MW) of grid-connected electrical battery storage



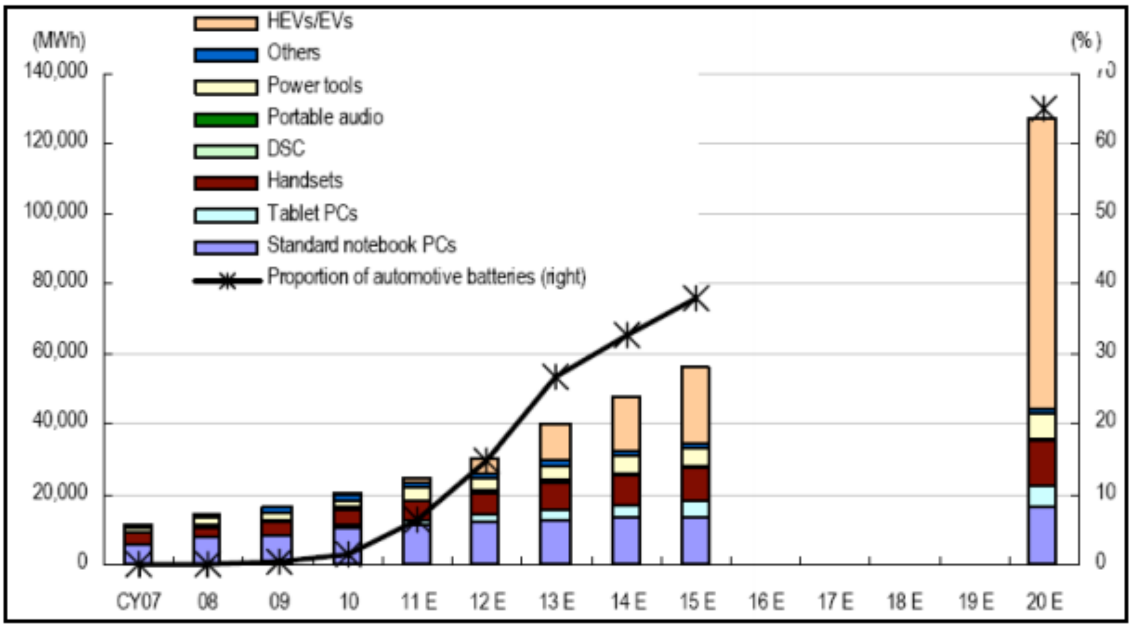
Source: US Department of Energy (2015) database based on "commissioned" date; CME analysis

In addition to grid-connected electrical storage, Li-ion battery storage use is growing for demand-side consumer goods such as electric vehicles, computers, mobile phones and power tools. Historical lithium ion demand side energy usage has continued to grow from 10 GWh in 2007 to an estimated 60 GWh in 2015 and forecast to double again by 2020[9]. The chart in Figure 5 shows lithium ion battery store energy usage by consumer category including but not limited to electrics vehicles (EVs), power tools, portable audio, digital still cameras (DSC), tablets and notebooks, and personal

[9] NEC (2012)

computers (PCs), etc. In time, the largest component of the demand-side energy (DSE) use is expected to come from EVs usage.

Figure 5. Lithium ion demand-side energy use



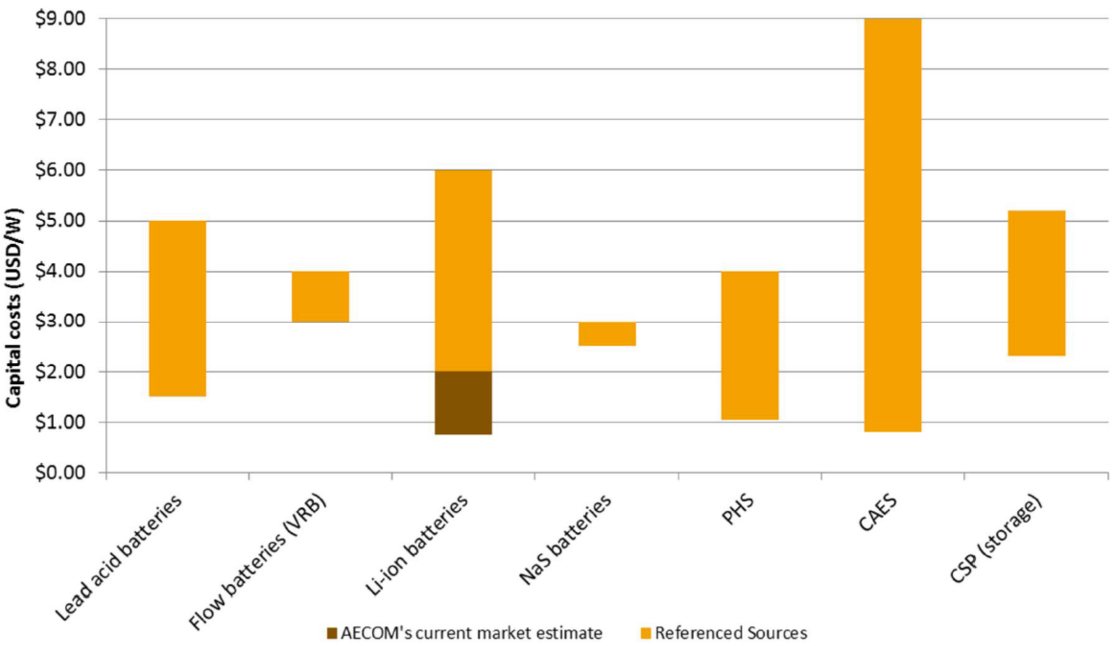
Source: NEC (2012)

2.3.6 Li-ion properties and costs

Lithium ion batteries, relative to others, are light, have high energy and power density and a slower loss of charge when not in use. The lower weight increases the opportunities for applications which requires a portable storage solution. The higher energy density and power density minimizes the footprint of the battery storage, enabling residential consumers with limited land to access to battery storage. The slower loss of charge when not in use has led to extensions of their lifetime, reducing degradation and maintaining output. The other benefit of lithium ion batteries are few maintenance requirements, reducing future maintenance costs. Lithium ion batteries are fast charging and are not affected by the chosen battery operation, improving the battery longevity. They are also relatively safe and have typical efficiencies above 90%, minimising the generation required to charge the batteries. Fthenakis and Nikolakakis (2012) provide a useful description in this area.

In addition to its inherent properties, the most recent capital cost estimate of battery storage technologies by AECOM (2015) (see Figure 6 for the cost comparison in USD/Watt) suggest the latest lithium-ion market estimates are now lower than all competing battery storage technology.

Figure 6. Energy Storage Capital Costs



Source: AECOM (2015)

3 Perspectives on the economics of battery storage

This section describes and explains the economics of battery storage from three perspectives: end users that control storage, non-network service providers that own or provide battery services and network service providers.

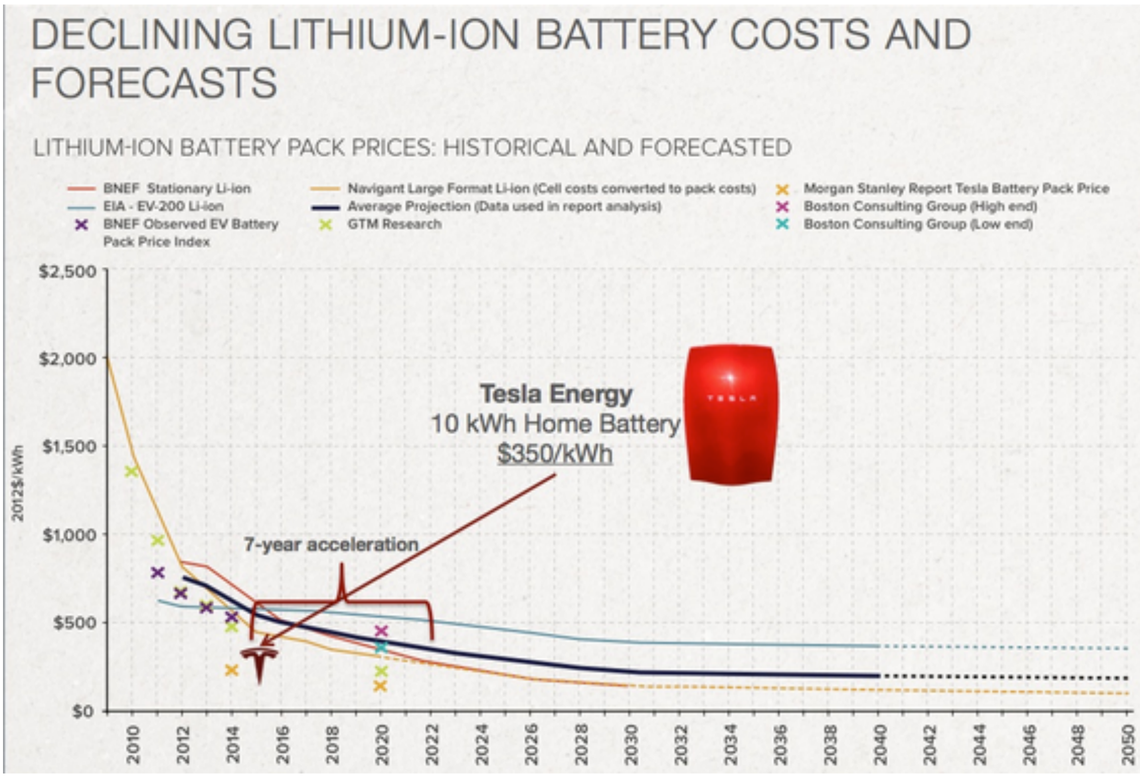
3.1 End-users

End-users that control batteries are able to use them to store electricity when it is inexpensive and using it or selling it back to the grid when it is more valuable.

To achieve this, households need to make an outlay in the battery probably - but not necessarily - as a capital sum. In deciding whether to make the investment in a battery, on economic criteria, the end user will compare the outlay to the present value of the benefits that the battery is expected to produce over its life.

The capital outlay of a system comprises the battery plus balance of system (BOS) costs, including inverters, charge controllers, monitoring and system installation. Figure 7 from the Rocky Mountain Institute charts current and projected future battery costs in US dollars per kWh capacity (we included the Tesla Energy battery for which prices have recently become available).

Figure 7. Lithium-ion battery costs and forecasts



Source: Rocky Mountain Institute (2015)

The main factors that affect the benefit that end users can obtain from batteries include: the extent to which the users' demand correlations with electricity prices; demand-side flexibility, the extent of temporal price differences and the cost of capital used to find the investment.

Demand correlation with price

A battery will be more attractive to an end user if their demand is highly correlated with prices (higher demand occurs when prices are higher) and they are unable to easily shift demand.

Temporal price differences

Obviously if there is a big difference between electricity prices at different times of the day or week, it is likely to be more valuable to be able to store electricity when it is cheaper and use it or sell it back when it is more expensive. Many factors will affect temporal differences including the structure of electricity tariffs (time-of-use tariffs with big differences between peak and off-peak prices) provide incentives for storage whereas flat-rate tariffs provide none. Similarly tariffs with peak demand charges will provide incentives for storage as long as the batteries can be used to reduce the peak, chargeable demand. End users with their own PV system will have a marginal production cost of zero. Batteries are more likely to be attractive if PV production that is surplus to requirement can be stored in a battery and re-used later in place of purchasing from the grid.

Cost of capital

The rate at which an end-user is likely to discount future benefits will affect the attractiveness of a battery. End users that expect high financial returns from their investment in batteries will require higher benefits. Some users may install batteries even if they do not provide financial returns. Other benefits they may value include greater grid independence and/or, maximising the use they derive from their own solar system..

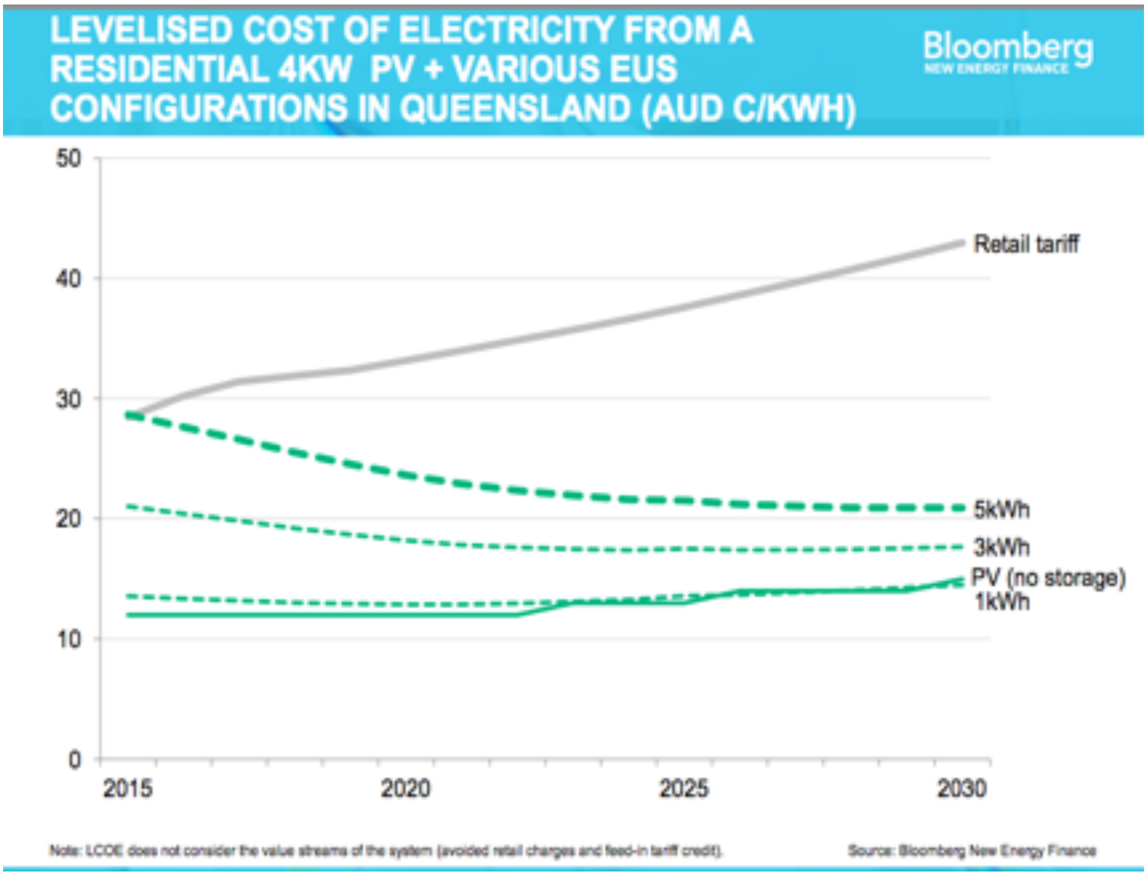
While it is straight-forward to identify the various factors that affect the benefits of batteries to end users, actually working out whether their financially attractive to individual users is very complex and the variables in the calculation are often quite uncertain.

The financial calculation at the end user level can be expressed as a net present value, pay-back period (discounted or undiscounted), internal rate of return or as a levelised cost of electricity (LCOE). LCOE is often used for the purpose of comparing the life-cycle average cost to an end use of installing a battery (with or without PV) compared to the cost of buying electricity from the grid.

Figure 8 and Figure 9 from Bloomberg New Energy Finance (BNEF) and Deutsche Bank respectively, show their calculations of the LCOE in Australia and the United States respectively.

The LCOE analysis by BNEF (2015) examines an end-user in Queensland installing rooftop PV (4 kW) and various end use storage (EUS) sizes (1 kWh, 3 kWh, 5kWh). The analysis suggests that any battery storage size equal to and less than 5 kWh coupled with PV is economic compared to the existing retail tariff in 2015. Beyond 2015, BNEF forecast a widening gap between the PV and storage LCOE and the retail tariff until 2030.

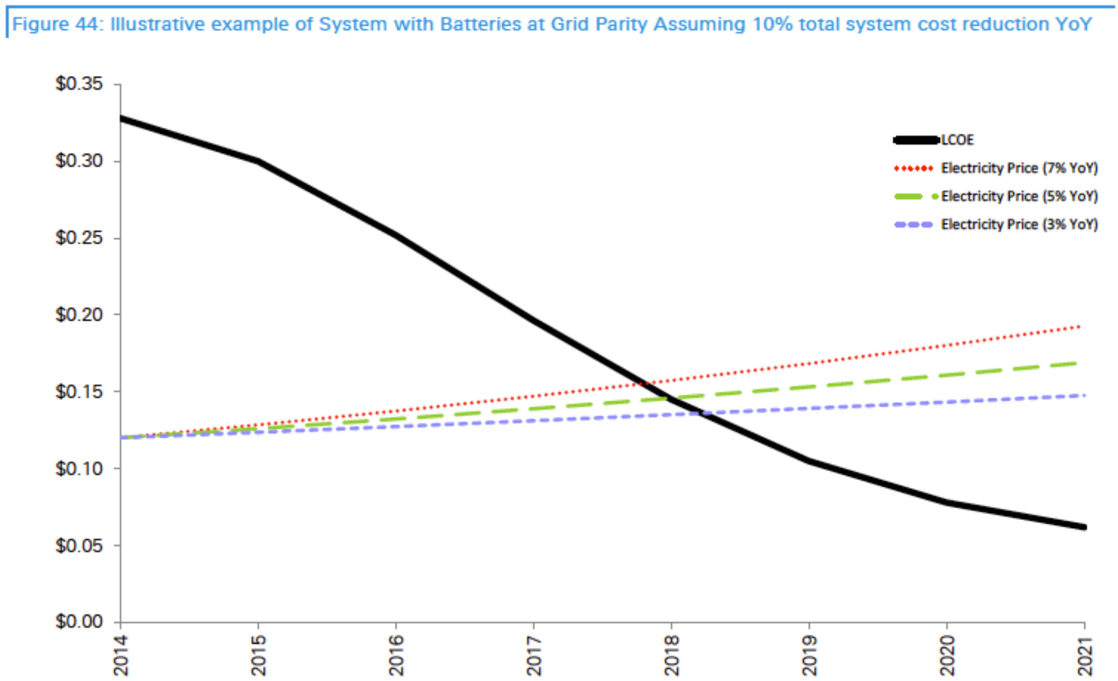
Figure 8. LCOE forecast for 4kW PV and storage residential customer in Queensland



Source: Bloomberg New Energy Finance (2015)

Deutsche Bank (2015) compares retail electricity tariffs for a household in the United States end-user with varying forecasts of future changes (3%, 5% and 7% were considered). Deutsche Bank analysis suggests the LCOE of battery storage will be equal to retail prices in 2018, and continue to decline through to 2021, with the analysis expressed in Figure 9.

Figure 9. LCOE illustrative economic calculation for battery storage system



Source: Deutsche Bank (2015)

3.2 Non-network service providers

We use the term "non-network service provider" to describe service providers that operate in the energy market but do not provide regulated services to consumers. For this category of participant, three business propositions seem possible:

- Own a grid-connected storage as an alternative to generation in providing electricity to end users; as a way to manage wholesale market price risks or as a way to provide storage services to end users',
- Selling batteries (with or without installation) to end-users;
- Building, owning and operating batteries at an end-user's premises (behind the meter).

An example in the first category is Hydro Tasmania's 3 MW / 1.6 MWh advanced lead acid battery system on King Island, Tasmania which stores excess renewable generation (wind and PV) and thereby reduces the alternative production of diesel-based generation.

An example of the second category is AGL Energy's recent announcement of battery storage offers to end-users.[10] Another example is Tesla Energy who have announced they will sell battery storage to Australian end-user excluding the inverter and installation costs.[11] Other Australian retailers including Red Energy, ActewAGL and Ergon Energy are trialing end-user battery storage sales.[12]

An example in the third category is Ergon Energy Retail who are offering PV and lithium ion storage, behind the meter. For the provision of the system (the program covers 33 households), the end-user will be asked to pay an $89 monthly fee to Ergon Energy Retail.[13]

One retailer in Western Australia, Synergy Energy, in partnership with Lendlease and Landcorp, will install PV for 100 homes and one, shared, lithium ion battery as part of a new housing development.[14]

3.3 NSPs

Batteries may be valuable to NSPs as an alternative to expanding or replacing networks. Batteries can also reduce the losses on distribution networks and by absorbing or producing reactive power can improve the voltage at the point of use thereby avoiding the need for other forms of power factor correction or network augmentation.

The battery investment criterion for an NSP will be whether the present value of avoiding an augmentation of the network is less than the cost of installing a battery. A clear description of this is set out in a report by UK Power Network (UKPN)[15] where

[10] Parkinson (2015a)

[11] Tesla Motors (2015)

[12] Parkinson (2015b)

[13] Ergon Energy (2015)

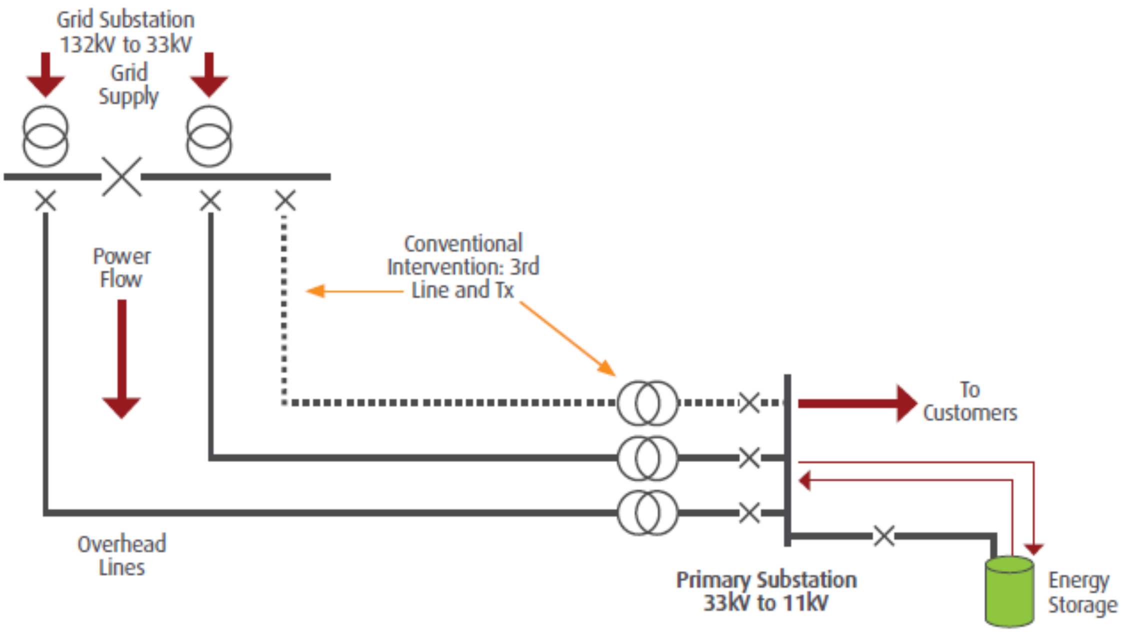
[14] Vorrath (2015a)

[15] UK Power Networks (2015)

UKPN evaluated the augmentation of a substation at Leighton Buzzard and examined the scope for battery storage to defer such augmentation.

At the substation, peak demands were temporarily exceeding the installed capacity. The conventional solution would have been to install an additional circuit and transform as indicated in the beige arrows in Figure 10.

Figure 10. Leighton Buzzard Reinforcement Options



Source: UK Power Networks (2015)

This would have added significantly more capacity than needed to meet the peak demand, resulting in significant amount of redundant capacity until demand once again caught up with supply. Various battery alternatives were considered adding between 6-8 MW of peak capacity and supplying 10-24 MWh of energy. The business case for the investment in this storage was whether the saving that could be achieved by deferring the large increase in the capacity of the substation by conventional means (an additional circuit and transformer) was more than the cost of the battery.

This equation is at the heart of the case for investment, by NSPs, in grid-scale battery capacity. In practice the calculations are complex and will be affected by many factors including whether the battery can be subsequently relocated and re-used elsewhere in the network (and if not its scrap value);

- local environmental, planning and safety factors;
- the NSP's cost of capital;
- supply reliability requirements;
- income from other services (such as the capacity to "black-start" the network or provided islanded supply to consumers downstream of the substation);
- technology risks, construction times and construction risks; and
- the rate at which future demand is increasing and the certainty of those demand projections.

As yet, there are limited examples of Australian NSPs installing grid-scale batteries. Ergon Energy are in the course of building 20 grid-connected lithium ion battery units (25 kVA / 100 kWh) on their Single Wire Earth Return (SWER) lines in rural Queensland. In Victoria, Ausnet Services have installed a 1 MW / 1 MWh lithium ion battery in Thomastown, an industrial zone near Melbourne. Also in Victoria, Powercor are in the process of developing a 2 MW / 2 MWh lithium ion battery to perform transmission support and provide ancillary services.

In all cases these batteries will be included in their regulated asset bases (RAB).

3.4 Australia battery storage projections

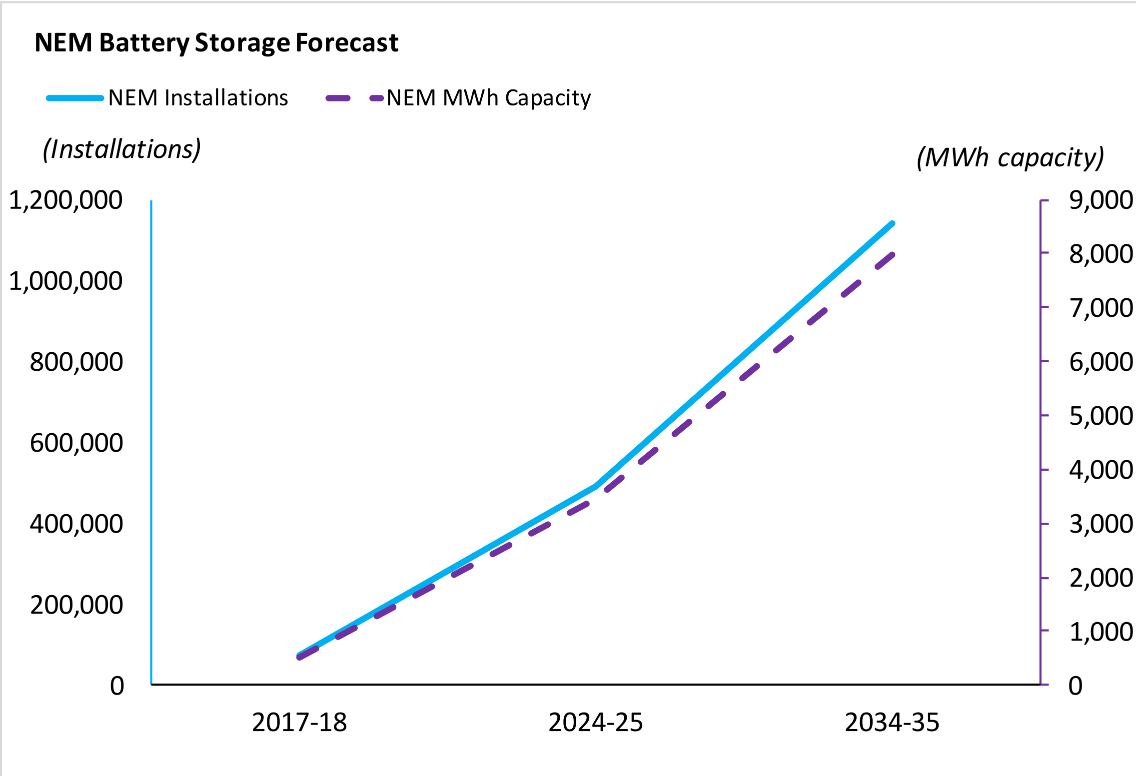
Projecting the uptake of battery storage systems is highly uncertain and dependent on a number of variables and factors discussed earlier in this Section.

Australian energy market operators and some analysts have made initial predictions on the growth of battery storage and its possible trajectory. The Australian Energy Market Operator (AEMO) operates the power market in the Southern and Eastern Australia states. Their information paper[16] in conjunction with their annual forecasting report, examined residential customer battery storage uptake including forecast projections for

[16] Australian Energy Market Operator (2015)

the financial years 2018, 2025 and 2035, as shown in Figure 11. In this figure, from AEMO's total MWh project, we estimate the number of installations assuming 7kWh per unit battery storage systems. We note the battery storage MWh projection does not translate into aggregate annual storage – this requires additional assumptions regarding the operating regime.

Figure 11. National Electricity Market (NEM) battery storage forecast (MWh capacity and installations)



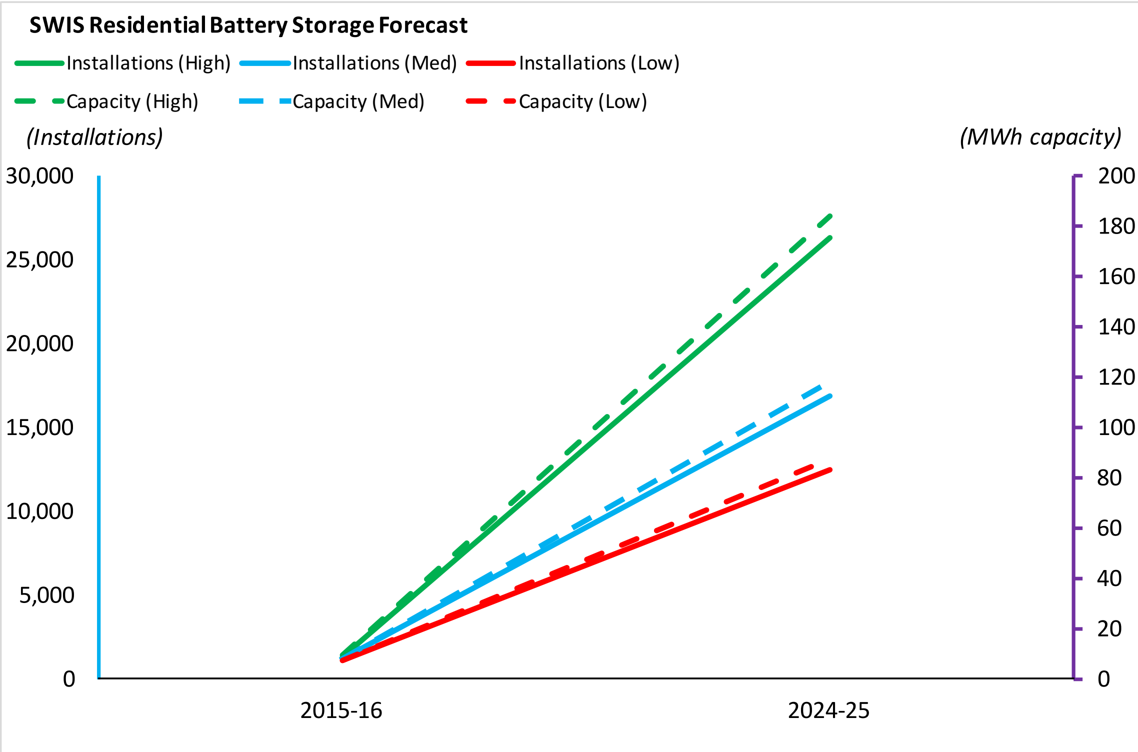
Source: Australian Energy Market Operator (2015); Installations assume 7kWh capacity per installation; CME analysis

In addition to AEMO's projection, the Independent Market Operator (IMO) in Western Australia released battery storage forecasts within their most recent annual demand forecast report[17]. These forecasts included storage capacity (MWh) as well as number of installations assuming each household installs a 7kWh battery storage pack. The forecasts cover the 2016 and 2025 financial years, which we represent graphically in

[17] Independent Market Operator (2015)

Figure 12. Their forecast is restricted to households, not including commercial or industrial customers.

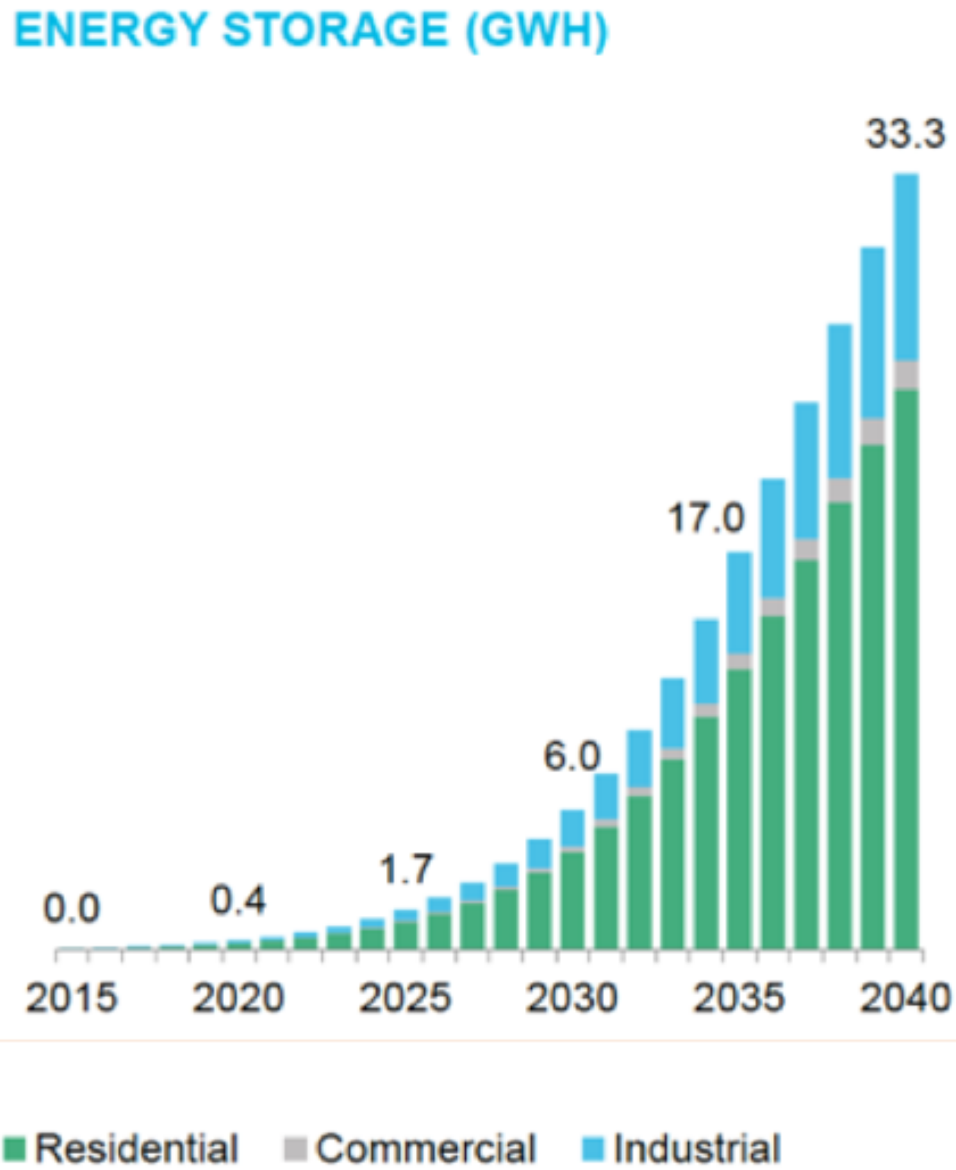
Figure 12. SWIS battery storage forecasts



Source: Independent Market Operator (2015); IMO assume 7kWh capacity per installation; CME analysis

Some analysts have proposed more bullish forecasts of battery storage uptake than AEMO or IMO. Bloomberg New Energy Finance (2015) analysis suggests the household market will dominate and they expect twice as much capacity per installation (14 kWh) than IMO. BNEF's projections distinguish between Residential, Commercial and Industrial as show in Figure 13.

Figure 13. Australia energy storage (GWh) forecasts



Source: Bloomberg New Energy Finance (2015)

4 Conceptual discussion

This section considers, conceptually, whether distribution NSPs should be allowed to include batteries in their RAB and thus have a guaranteed ability to recover their investment in batteries through regulated charges levied on all their customers.

In the National Electricity Market (NEM), distribution (i.e. the businesses of providing carriage of electricity on the lower voltage networks) by the 13 distribution NSPs has been separated from the business of retailing or producing electricity.

Legal, functional and subsequently ownership separation between distribution NSPs started in Victorian in the early 1990s and has since extended to other parts of the NEM. In parts of Queensland, all of Tasmania the Australian Capital Territory the incumbent retailer and distribution network service provider are functionally and legally separated but they are owned by the same entity. This separation occurred after the separation of the ownership and operation of transmission networks from generation (and pumped hydro storage).

The main justification for functional and legal separation is the need to achieve non-discriminatory (open) access to distribution networks in order to facilitate competition in the retailing of electricity to end users.

The question of whether distributors should be allowed to control batteries has many parallels to the question of whether transmission companies should be allowed to control generation (and storage). This section therefore starts by revisiting the justification for the separation of generation (and storage) from transmission. The section then examines the case for and against the separation of batteries from distributors.

4.1 The separation of transmission and generation

The transmission networks in the NEM were separated from the rest of the industry in the mid-1990s, in preparation for the development of the wholesale market (the NEM), which formally began operation in 1998. The adoption of this industry structure in Australia followed innovations first adopted in Chile and Great Britain in the 1980s. The separation of transmission networks from electricity producers is now the norm in developed economies.

The main justification for the separation of the monopoly network service activity from the contestable production activity is that this is a necessary pre-condition for competition in the wholesale production of electricity. This is because control of the transmission network by a generator could mean that that generator could use the transmission network to detrimentally affect competitors' access to customers.

Another argument is that a transmission can be a close substitute for, or complement to, generation. Transmission can substitute for generation where it is possible to meet electrical demands by extending the network, rather than constructing a power station at or close to the customers' point of use. Transmission can complement generation: by connecting a generator to a network, the transmission line can expand the generator's addressable market.

The complementarity and substitutability of generation and transmission means that if markets are to be made in generation, then functional and legal separation is essential. Prior to separation "integrated resource planning" purported to offer the prospect of optimal investment decision-making across both generation and transmission. This meant decisions to expand or contract generation or transmission capacity were made by the same decision-maker and this meant competing options were evaluated against each other at the time of the investment decision.

By separating generation from transmission, such "integrated resource" decision-making is no longer possible. The decision to vertically separate recognised the problem that separation meant the loss of co-ordination through control. Decision-makers were, evidently, convinced that this loss did not exceed the benefits that competition in generation would offer.

In their path-breaking study of the Australian electricity industry, which recommended that transmission be separated from generation, the Industry Commission suggested that the benefits of co-ordination (between transmission and generation) through ownership were probably overstated and that these co-ordination benefits:

"*may be captured effectively by alternative means (e.g. by formal or informal agreements to coordinate some activities)*".[18]

Biggar (2009) provides a comprehensive overview of the "policies" needed to ensure successful co-ordination in the context of the vertical separation of transmission from generation. He suggests that foremost amongst these is that transmission prices reflect the (short run) marginal value of transmission.

Biggar (2009) also refers to other significant "policies" needed to ensure effective co-ordination, including ensuring effective competition in generation, that losses and network constraints are reflected in the wholesale market, that transmission planners are able to rely on accurate price forecasts, that ancillary services can be efficiently procured, and finally that transmission investment is efficient this latter requirement being particularly dependent on the regulation and governance of the transmission service providers.

It is far beyond the scope of this paper to assess whether these policies have been successful. The many submissions to rule changes, reviews by the AEMC, applications of the regulatory tests for major transmission developments (including interconnector developments) suggests that market participants have a range of views on just how successfully (or unsuccessfully) the operation and investment in transmission has been coordinated with the wholesale electricity market.

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[18] Industry Commission (1991) Page 15

Biggar's observation is that "*the current arrangements in the NEM are largely internally consistent*" but singles out for particular criticism, failures in transmission pricing.

4.2 The separation of transmission and storage

The discussion to this point has focussed particularly on co-ordination between generation and transmission in the context of vertical separation. The same issues apply in respect of the separation between storage and transmission.

Australia has three large-scale transmission connected storage facilities: Shoalhaven (240 MW), Wivenhoe (500 MW), and Tumut 3 (600 MW). These were all built more than 30 years ago when the industry was vertically integrated. When generation was separated from transmission in the lead up to the creation of the NEM, these pumped hydro storage plants were considered to be akin to generators so were separated from transmission when the vertical separation took place, reflecting the rationale in the previous sub-section.

Internationally there is limited experience of pumped-hydro plant development. One interesting case is cited in Sioshansi et al. (2011) and repeated in Box 1. This describes a decision of the Federal Energy Regulatory Commission in the United States to reject an application for the treatment of a proposed pumped hydro plant as a regulated investment. The rationale for the separation of pumped hydro from transmission is evident from this.

Box 1. Proposed Nevada Hydro pumped storage development

In 2010, Nevada Hydro, proposed building the 500 MW Lake Elsinore Advanced Pumped Storage (LEAPS) plant in southern California plant along with a new transmission corridor between the Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E). Nevada Hydro claimed that both projects provide transmission benefits—the new corridor increases transfer capacity between the SCE and SDG&E regions while LEAPS relieves transmission by shifting loads from congested to uncongested periods.

Nevada Hydro requested that its investments be recovered through regulated charges. Nevada Hydro also proposed a novel operational arrangement whereby the California Independent System Operator (CAISO) would dispatch LEAPS to maximize transmission relief benefits.

The Federal Energy Regulatory Commission (FERC) allowed only the transmission assets to be recovered through regulated charges, it denying Nevada Hydro's other requests. It concluded that the CAISO dispatching LEAPS would jeopardise the independence required of a market operator, since this would be akin to it owning and operating generation that can affect the market.

Moreover, the FERC concluded that since LEAPS would provide its transmission service by participating in the energy market, it would not exclusively be a transmission asset. Thus it concluded that it would be inappropriate to recover through regulated charges, an investment that it viewed as providing generation services, which should instead recover costs through the market.

4.3 The separation of distribution and storage?

Does the separation of a pumped hydro power station from transmission NSPs provide the precedent for the separation of battery storage from distribution NSPs? The rest of this section breaks this question down into four subsidiary questions:

- Can distribution prices correctly convey the temporal and locational value of distribution (in which case "the market" has all the information it needs to decide where to invest in batteries)?
- Are batteries likely to be particularly valuable to distribution network service providers (moreso than pumped-hydro is to transmission network service providers)?
- Will a distributor's control of batteries have a significant impact on the energy market?
- Can regulatory arrangements protect consumers from inefficient over-investment if distributors are allowed to own and operate batteries?

Question 1: Can distribution prices correctly reflect the temporal and locational value of distribution?

The earlier discussion on transmission pricing drew attention to the importance of prices that reflect the value of transmission at different points on the network. Prices that are established in this way provide signals for the efficient production and investment in generation. Achieving such "efficient" prices is difficult, not least because of the complexity of establishing prices at multiple locations. In addition, even if such locational prices (often called nodal prices) are calculated (as is the case, for example, in electricity markets in the United States and New Zealand), they are still distorted by charges for the use of transmission networks, which are typically set so as to recover average costs.

In distribution, these issues are even more problematic. There are many reasons for this. Firstly, there are many more nodes in a distribution network than in a transmission network. This makes it even more complex to establish and communicate locational prices. Secondly, relative to transmission, distributors need to take greater account of the preference some consumers have for stable prices. Political pressures (for example, non-discrimination between rural and urban prices) and administrative constraints (for example, in communicating prices that may need to change frequently if they are to accurately reflect the temporal and locational value of distribution) also diminish the scope for locational prices that vary in short time intervals.

If distribution prices are not able to accurately reflect the economic (short run marginal) value of distribution then prices can not be relied upon to signal to market participants (and end users) where and when batteries may be more advantageous than network alternatives. In the place of prices, greater reliance is therefore needed on other mechanisms – such as the engineers' knowledge of the balance of supply and demand at different points in the network to promote efficient investment in networks, demand response and batteries. Inevitably, this implies that ownership and control of batteries by the same organisations that own and plan network services would be helpful.

Question 2: Are batteries likely to be particularly useful to distribution network service providers?

As we noted earlier, the Industry Commission's assessment was that while transmission and generation could be substitutes and complements, the benefits of integrated resource planning were likely to be overstated. Is this also likely to be the case for batteries in the case of electricity distribution networks?

Our understanding is that at present distributors do not yet consider that grid scale battery storage is (generally) a sufficiently competitive alternative to other options such as augmenting substation capacity or building bigger cables or lines. If they are correct in this view then, for now at least, it will not matter if they are precluded from owning and operating batteries.

If grid-scale storage becomes widely competitive with conventional network alternatives then co-ordination failures will become more important. The distribution grid is far more extensive (and expensive) than the transmission grid and accounts for about four times as much of the typical small consumers' electricity bill.

Grid-scale batteries – particularly lithium-ion batteries – have some particularly valuable properties such as scalability, mobility, flexibility, responsiveness and low environmental impact at point of use. This may mean that grid-scale storage may become a relatively more valuable substitute for, and complement to, distribution augmentation than pumped hydro is to transmission.

If this is correct then coordinating development of distribution networks and batteries will be particularly valuable.

Question 3: Will distributor control of batteries have a significant market impact?

This will depend, of course, on the volume of battery capacity that distributors controls. To inform the possibilities, we set out a hypothetical analysis. The simultaneous peak demand in the NEM is currently around 33,000 MW.[19] Assuming, for the purpose of illustration, that battery storage capacity equivalent to 10% of this demand was available for 15 minutes, this would translate into 8,250 MWh of storage capacity. Assuming an average grid-connected battery installation size of 10 MWh, this would be 825 grid scale battery installations.

Assuming installed cost of $500 per kWh, this amount of battery capacity would cost $4.2 billion. Assuming this level of capacity was installed over eight years, would mean an outlay of $0.7bn per year. By comparison, over the period from 2006 to 2013, distributors in the NEM incurred capital expenditures of $44.5bn or $5.6bn per year on average. While a $0.7bn per year outlay on grid-scale batteries would be significant, it is 12.5% of total distributor annual capital outlay.

This may be plausible if the technology proves to be a viable substitute to grid augmentation. Assuming that distributors controlled this amount of battery capacity, such an investment would undoubtedly have significant markets impacts. This would seriously undermine the separation between monopoly distribution service providers and the energy market.

Question 4: Can regulatory arrangements protect consumers from inefficient over-investment in batteries?

Electricity distributors are subject to periodic controls of their revenues. Though initially based on a regulatory form ("RPI-X" price caps applied first in British

[19] Australian Energy Regulator (2015)

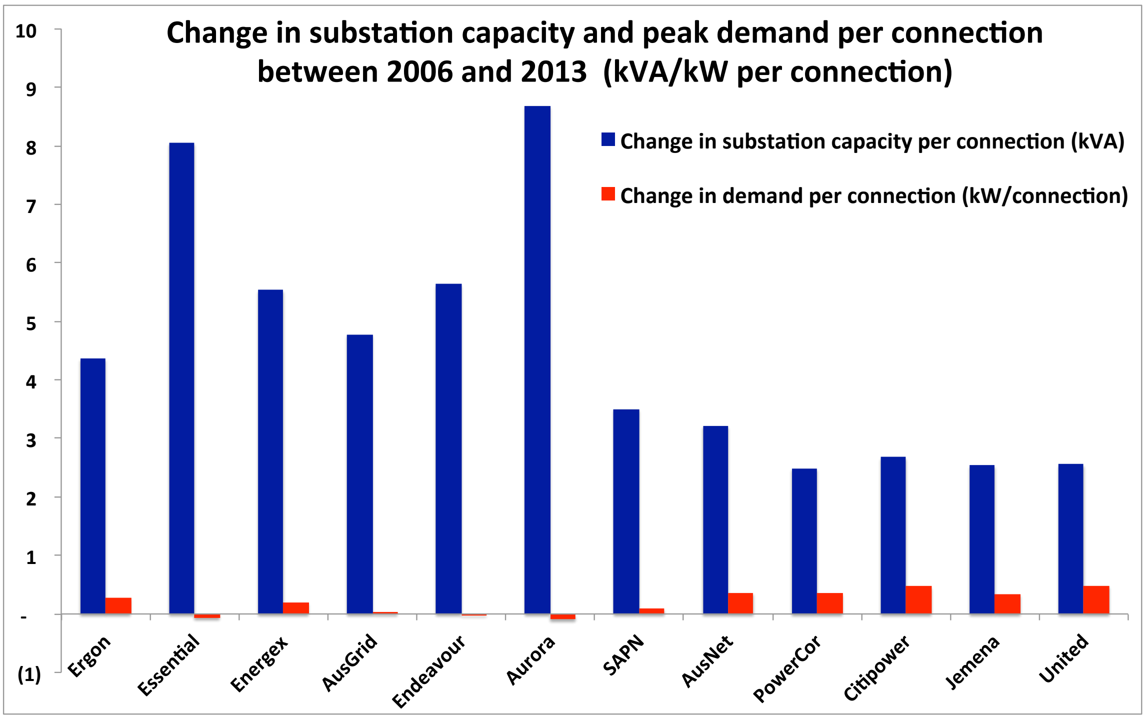
Telecom's price control at the time of privatisation) in practice the arrangements in Australia have changed significantly from the RPI-X form.

Ostensibly, this form of regulation is purported to provide incentives to efficiency by allowing the regulated entities to improve the rate of the return on their investment by spending less than the regulatory allowances. However, this conjecture is affected by many factors including in particular, the difference between the regulatory determination of the cost of capital and the distributors' actual cost of capital: if the later is lower than the former, then the regulatory regime actually provides financial incentives to spend more than the regulatory allowances.

Indeed the evidence is strongly suggestive that, particularly in the case of Government-owned distributors, this has been the case. Consequently we must ask that if batteries owned by distributors are to be included in the regulated asset base, is there reason to be confident that consumers can be protected through regulation, from inefficient investment by distributors in batteries?

Figure 14 below compares the increase in substation capacity of distributors in the NEM between 2006 to 2013 (the blue bars), compared to the change in demand (the red bars), both normalised by the number of consumers. It is clear from this that expenditure on substation capacity has far exceeded the increase in demand and that consumers are paying for large amounts of substation capacity that is not necessary.

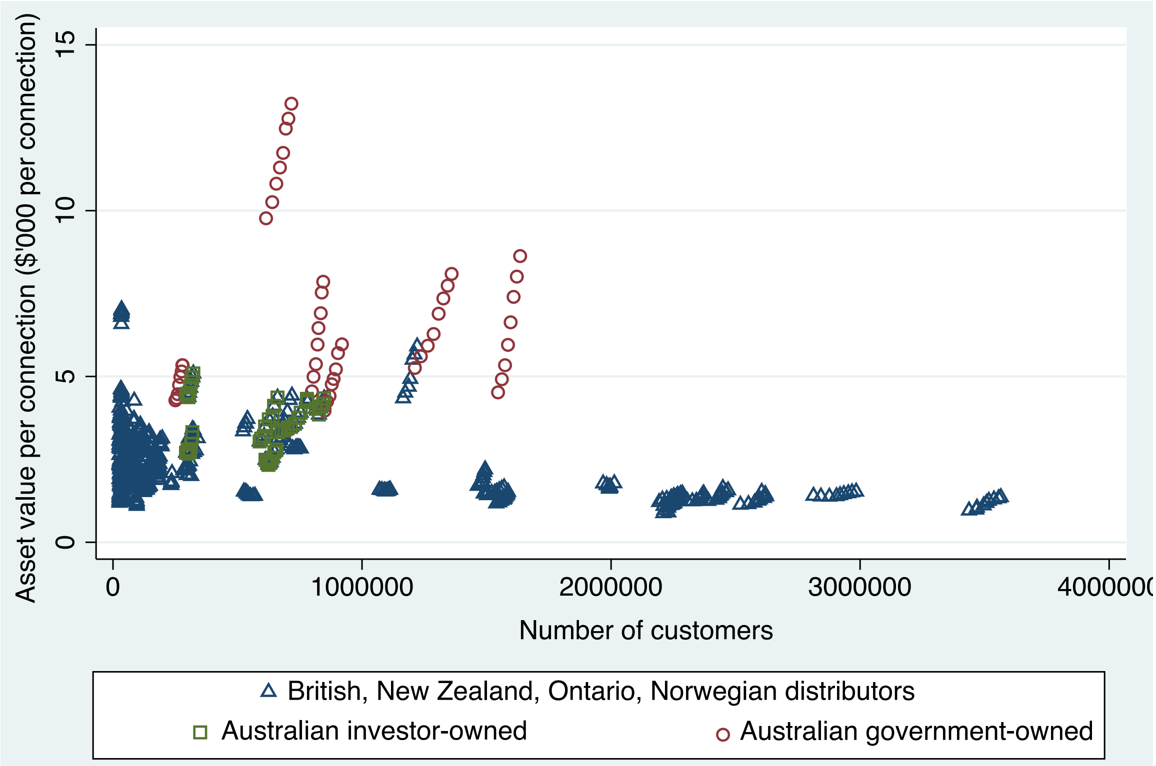
Figure 14. Change in substation capacity and demand per connection between 2006 and 2013 for Australian distributors



Source: Regulatory Information Notices, CME analysis

Sub-station capacity is the single largest category of distributor capital expenditure. Concerns about sustained excessive expenditure can be inferred by comparing the RAB of Australian distributors to those of distributors in other countries. Figure 15 is a scatter chart of the regulated asset values per connection versus the number of connections from 2006 to 2013 of all electricity distributors that served more than 35,000 connections in the NEM in Australia, in New Zealand, Ontario, Great Britain and Norway. The extraordinary outcomes delivered by all six government owned distributions in Australia (the red circles) stands out starkly when compared to those of government and privately owned distributors in these other countries.

Figure 15. Regulated asset value per connection versus number of connections*



Source: CME analysis; Data from Australia (regulatory decision documents and Regulatory Information Notices), Great Britain (Mr Dermot Nolan, Ofgem), Norway (Professor Tooraj Jamasb), New Zealand (New Zealand Commerce Commission), Ontario (Ontario Energy Board)

* (for all electricity distributors that served more than 35,000 connections in the National Electricity Market in Australia, in New Zealand, Ontario, Great Britain and Norway from 2006 to 2013. Monetary values in 2014 Australian dollars all foreign currency converted at PPP exchange rates).

The comparisons in Figure 14 and Figure 15 suggest that the existing regulatory arrangements have failed to protect consumers from expenditure by distributors that has proved to be wasteful. Consumers can (and should) ask that if the regulatory arrangements are unable to protect consumers then surely effort should be made to limit, not extend the range of possible assets that distributors might be allowed to own and include in their regulated asset bases.

4.4 Synthesis

This section started by describing the rationale and history for the separation of generation from transmission and subsequently the separation of storage from transmission. It then asked whether the precedent set by the separation of storage from transmission would suggest that batteries should likewise be separated from distribution so that monopoly distribution NSPs should not be allowed to include batteries within their regulated asset base.

This raised four subsidiary questions. The first two of these: can distribution prices provide signals for efficient investment in batteries and are batteries likely to be relatively more valuable to distributors than storage is to transmission NSPs, support a conclusion that it would be beneficial for distributors to be involved in the ownership and operation of batteries and for these to be included in their RABs. The answers to the two other questions: is it plausible that grid-scale batteries can have a significant impact on the market and can we be confident that regulators can protect consumers from inefficient investment in batteries by NSPs suggest that it would be beneficial for NSPs not to be able to include investment in batteries in their RAB.

At a conceptual level, the analysis is therefore inconclusive: there are good reasons for allowing the regulated development of batteries and there are other good reasons for disallowing this. The issue is developed further in Section 0 which describes and evaluates a range of options.

5 Approaches adopted elsewhere

This section describes the approaches taken to the regulation of storage in California, Britain and New York.

5.1 California

In 2010, the Government of California passed a law (Assembly Bill (AB) 2514)[20] to encourage California to incorporate energy storage into the electricity grid. The law envisaged that energy storage would provide a multitude of benefits to California, including supporting the integration of greater amounts of renewable energy into the electric grid, deferring the need for new fossil-fueled power plants and transmission and distribution infrastructure, and reducing dependence on fossil fuel generation to meet peak loads.

The law anticipated that an energy storage system would use mechanical, chemical or thermal processes to store energy that was generated at one time for use at a later time. The law required publicly-owned utilities to propose targets to the California Energy Commission. The law also required the California Public Utilities Commission (CPUC) to set targets for the state's investor-owned utilities to procure energy storage systems. These investor-owned utilities serve by far the greatest number of electricity consumers in California.

In October 2013, the CPUC adopted an energy storage procurement framework and established an energy storage target of 1,325 MW by 2020 for the three largest investor owned utilities. [21]

Consistent with the law (AB 2514) CPUC's energy storage procurement framework is guided by three objectives:

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[20] California Legislative Information (2010)

[21] California Public Utilities Commission (2013)

- Optimiszation of the grid, including peak reduction, contribution to reliability needs, or deferment of transmission and distribution upgrade investments;
- The integration of renewable energy; and
- The reduction of greenhouse gas emissions to 80 percent below 1990 levels by 2050, as per California's goals

While energy storage may serve additional purposes within California's energy supply, the CPUC applied these three overarching goals in setting procurement targets, designing procurement, and evaluating progress.[22]

In addition to targets for the investor owned utilities, CPUC determined obligations (as a percentage of 2020 peak demand) for the much smaller Community Service Aggregators and numerous small independent retailers.

In developing their targets – three years after the law was enacted - CPUC staff in consultation with the industry and consumers progressively developed the arrangements.

CPUC staff summarised the "end use" for storage as shown in Figure 16.

[22] California Public Utilities Commission (2013)

Figure 16. Storage and uses

STORAGE GRID DOMAINS (Grid Interconnection Point)	REGULATORY FUNCTION	USE-CASE EXAMPLES
Transmission-Connected	Generation/Market	**(Co-Located Energy Storage)** Concentrated Solar Power, Wind + Energy Storage, Gas Fired Generation + Thermal Energy Storage
		(Stand-Alone Energy Storage) Ancillary Services, Peaker, Load Following
	Transmission Reliability (FERC)	Voltage Support
Distribution-Connected	Distribution Reliability	Substation Energy Storage (Deferral)
	Generation/Market	Distributed Generation + Energy Storage
	Dual-Use (Reliability & Market)	Distributed Peaker
Behind-the-Meter	Customer-Sited Storage	Bill Mgt/Permanent Load Shifting, Power Quality, Electric Vehicle Charging

Source: California Public Utilities Commission (2013) - page 14

CPUC did have discretion to not set targets if it so chose, but decided that there were market barriers hindering broader adoption of emerging storage technologies including[23]:

1. Lack of definitive operational needs;
2. Lack of cohesive regulatory framework;
3. Evolving markets and market product definition;
4. Resource Adequacy accounting;

[23] California Public Utilities Commission (2012)

5. Lack of cost-effectiveness evaluation methods;
6. Lack of cost transparency and price signals (wholesale and retail);
7. Lack of commercial operating experience; and
8. Further define the energy storage interconnection process.[6]

The Commission did, however, suggest that the long-term goal would be to eliminate targets when the storage market is more mature, sustainable, and able to compete to provide services alongside other types of resources. It suggested that the storage framework it developed "*will encourage the development and integration of cost-effective energy storage systems in California's electric system in the future*."[24]

The outcome of the Commission's work were targets set for each of the investor-owned utilities and specified by the level at which such storage is connected (in the transmission or distribution network or directly to customers). Targets were set for each year as shown in Figure 17.

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[24] California Public Utilities Commission (2013)

Figure 17. California Storage Targets (Megawatts)

Storage Grid Domain Point of Interconnection	2014	2016	2018	2020	Total
Southern California Edison					
Transmission	50	65	85	110	310
Distribution	30	40	50	65	185
Customer	10	15	25	35	85
Subtotal SCE	**90**	**120**	**160**	**210**	**580**
Pacific Gas and Electric					
Transmission	50	65	85	110	310
Distribution	30	40	50	65	185
Customer	10	15	25	35	85
Subtotal PG&E	**90**	**120**	**160**	**210**	**580**
San Diego Gas & Electric					
Transmission	10	15	22	33	80
Distribution	7	10	15	23	55
Customer	3	5	8	14	30
Subtotal SDG&E	**20**	**30**	**45**	**70**	**165**
Total - all 3 utilities	**200**	**270**	**365**	**490**	**1,325**

Source: California Public Utilities Commission (2013) – page 15

Utility-Owned versus Third Party Storage

One of the many interesting issues discussed in the developments of CPUC's targets was whether the investor owned utilities or third parties should own the storage connected to transmission or distribution networks. Storage connected at customers' premises was not in dispute (storage would be owned by third parties or consumers but not the utilities).

CPUC's proposals was that each utility may meet up to fifty percent of its distribution system procurement target through utility-owned energy storage. Assets owned by the utility would be included in the regulated asset base of their transmission or distribution businesses if approved. But if the utility was proposing utility-owned storage, it would also have to offer to procure third-party owned storage through a competitive solicitation.

The investor-owned utilities disagreed with this and suggested that the regulated utilities should own all the storage connected to distribution and transmission networks because the utilities are responsible for planning and operating the distribution system. They suggested that:

" .. the energy provided by the energy storage system must be delivered in a timely fashion, in specific locations, with sub-second control and with a high level of certainty."

Consequently, they suggested that relying on third party storage could lead to significant reliability issues. CPUC resisted these arguments, concluding[25]:

"It is true that LSEs [load serving entities – what in Australia would be called distribution network service providers], given their statutory responsibility, have proven experience, capability, and history, to ensure reliability goals are met. However, as we have seen with specific opportunities such as "distributed peaker" projects or transmission upgrades within FERC jurisdiction, there is room to allow for different types of economic or policy driven storage projects that meet different needs, cost requirements, and other criteria. Therefore, we do not believe it makes sense to allow 100% utility ownership in transmission and distribution without first determining which specific applications or circumstances are best suited for utility ownership versus third-party providers.

In light of the above, we find that the utility ownership of storage projects should not exceed 50 percent of all storage across all three grid domains at this time. In other words, utilities may own no more than half of all of the storage projects they propose to count toward the MW target, regardless of whether it is interconnected at the transmission or distribution level, or on the customer side of the meter. We believe that setting this limit will ensure that any viable market options are not preempted. "

Finally, the definition of eligible technologies has been a complex issue in the California debate. Hydro generation greater than 50 MW is unequivocally excluded, but beyond

[25] California Public Utilities Commission (2013) Page 51

that a wide definition has been applied in accordance with Section 2835(a) of the Californian Public Utility Code. Under this code, an "Energy Storage system" means[26]:

"commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereby dispatching energy … and an "energy storage system" shall do one or more of the following:

(A) Use mechanical, chemical, or thermal processes to store energy that was generated at one time for use at a later time.
(B) Store thermal energy for direct use for heating or cooling at a later time in a manner that avoids the need to use electricity at that later time."

As we understand it, a definitive position of which technologies qualify as storage is not year clear. Batteries of all forms are obviously included, but contention areas seem to be biogas storage, electrical vehicles that draw demand from the grid but don't send it back ("V1G") and some applications of thermal energy storage when integrated into generating resources.

5.2 Britain

Unlike in California or New York, in Britain there have not been any significant changes to regulatory or market arrangements to facilitate the entry of grid-connected batteries. The British developments are relevant to Australia since their regulatory arrangements (unbundled transmission and distribution) are similar to ours. While regulatory or policy changes have not yet occurred (or been raised by policy makers or regulators) there have been numerous trials funded largely by the Low Carbon Networks Fund operated by the Office of Gas and Electricity Markets. This sub-section examines the recent developments and draws out topical issues.

Smarter Network Storage

[26] California Public Utilities Commission (2014) page 59

The SNS is a program of work undertaken as part of the Low Carbon Network Fund. A report produced as part of this program focussed on the "Regulatory and Legal Framework" for storage in Great Britain. Some of the key points from this report include [27]:

- Grid-connected storage (in Great Britain) is by default treated as generation in the regulatory framework;
- Under de minimus rules there was scope for British distributors to participate in storage until the value of storage was greater than 2.5% of the equity value of the distributor (formally distributors in Britain are not allowed to own and operate storage assets that require a generation licence but this is not a problem unless the de minimus restriction is breached);
- It was not clear how storage assets would be treated in regulatory price controls.

The report recognised the impact of storage on competition in the energy market. It considered a variety of ways that distributors could own, contract and operate batteries connected to the network.

A separate report[28] as produced as part of the Smarter Networks Fund, focused specifically on business models for distributor participation in grid-connected storage. It distinguished five possible "business models", set out in
Figure 18 below:

Figure 18. Grid storage business models

[27] Poyry & UK Power Networks (2013)

[28] Baringa & UK Power Networks (undated)

Increasing commercial risk for DNO

Model	Key points	Comments
DNO Merchant	Full merchant risk, exposed to power price and balancing services	• DNO builds, owns and operates the asset. Full operational control. • DNO monetises additional value streams directly on a short term basis (e.g. trading). • Possible barriers: Costs of accessing the market, DNO skills and capabilities, regulation and shareholder expectations of risk.
DSO	DNO exposed to incentive scheme	• DNO builds, owns and operates the asset. DNO has full operational control. • DNO has DSO role; coordinating portfolios of flexibility for both distribution and wider system benefit through a centralized control mechanism. • DNO commercial risk is dependant on design of incentive scheme.
DNO Contracted	DNO exposed to construction and operational risks	• DNO builds, owns and operates the asset. DNO has full operational control. • Prior to construction, long term contracts (e.g 10 years) for the commercial control of the asset outside of specified windows are agreed. • Dependant on the feasibility of long term contracts.
Contracted Services	Low commercial risk for DNO	• DNO offers a long term contract (e.g. 10 years) for services at a specific location with commercial control in certain periods. • Third party responsible for building, owning and operating the asset and monetising additional revenue streams.
Charging Incentives	No guarantee of asset being build	• DNO sets DUoS to create signals for peak shaving that reflect the value of reinforcement. • Barriers: no operational control for DNO, therefore no guarantee on security.

Increasing commercial risk for Third Party

Source: Baringa & UK Power Networks (undated)

For the purpose of making these terms tractable in the Australian debate we can summarise these business models as follow:

- **DNO Merchant:** is a where distributors would not seek to recover investments in batteries through regulated charges;
- **DSO:** envisages the situation that the operation of the distribution has been been separated from its ownership and the part that continues to own the network assets (the DNO) owns and operates batteries and recovers the cost through regulated charges (this has many resonances in the arrangements currently being pursued in New York, described later in this section);
- **DNO Contracted:** is where distributors own and operate batteries but enter into contracts with others for the operation of the batteries within specified technical operating parameters;

- **Contracted Services:** is where distributors do not own or operate the batteries but instead contract with others for the services provided by batteries (this is similar to the Orkney model described below);
- **Charging Incentives:** is where distributors have no involvement in the ownership, operation or procurement of the services provided by batteries. The motivation to own or operate batteries is meant to be provided through economically efficient network charges.

Interestingly, the report's authors concluded their preference for "DNO Contracted" and "Contracted Services" as the two lead business models for further consideration. The DNO Merchant model was excluded mainly because of the requirement for the DNO to build a trading capability and take wholesale market risk. The DSO model, while attractive in principle, was excluded at this time because the underlying regulation that would define this model has yet to be developed and as such cannot be critically appraised. The Charging Incentives model was excluded because it provides no guarantee of the storage being built or, once built, being available to provide network security.

In addition to these Smarter Network Storage projects there have been a number of smaller "pilots" and research projects – such as the Sola project in Bristol - focused mainly on technical issues associated with distributed generation and battery storage, rather than regulatory and market arrangements.

Finally, a 2MW grid-connected lithium-ion battery installed on the Scottish island of Orkney in 2013 deserves special mention. Scottish and Southern Energy Power Distribution (SSEPD) (the local monopoly distributor) issued a tender to procure "congestion management services" to SSEPD to allow it to manage network constrains on the island. SSEPD has had prior experience in owning and operating batteries on the isolated island power systems. The novelty was that the tender had no specification of storage technology, dimension or who was eligible to provide the service. Indeed the tender did not specify the provision of the service through a battery.[29] In the event,

[29] Vasconcelos et al. (2012) pg. 32

Scottish and Southern Energy (a major energy producer and retailer) won the tender and it will own and operate the battery to provide the contracted services to the distributor.

5.3 State of New York

The proposed changes to the organization and regulation of networks and retail businesses in New York State in response to the rise of distributed generation and storage is, from what we can see, by far the most ambitious and decisive response. The program under which these changes are being prosecuted is called the "*Reforming the Energy Vision*" program. The New York State Governor has championed the reforms, which aim to:

"reorient both the electric industry and the ratemaking paradigm toward a consumer-centered approach that harnesses technology and markets. Distributed energy resources (DER)[3] will be integrated into the planning and operation of electric distribution systems, to achieve optimal system efficiencies, secure universal, affordable service, and enable the development of a resilient, climate-friendly energy system".[30]

5.3.1 Elaboration of the rationale

The State of New York Public Services Commission (NYPSC) was tasked with implementing the Governor's vision. In developing its response it identified numerous challenges and opportunities which were grouped under four headings:

- Regulatory models and economic efficiency;
- System modernisation for a digital economy;
- Clean energy and environmental responsibility
- Universal service.

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[30] Governor Andrew M. Cuomo (2015)

The prospect of greater storage is described as one of the opportunities (under the "regulatory models heading" and "realizing the potential of storage and innovative technologies" sub-heading). On this the NYPSC says the following:

"In recent years, the cost of various storage technologies has declined, and their capabilities have increase. In addition to various forms of battery storage, building based thermal storage allows business and residential consumers to reduce bills through use of sophisticated sensors, thermostats and building control systems. This ability to use information to obtain the advantage of thermal storage, as well as deployment of batteries and other forms of storage located on customer premises or at key locations in the distribution system, has the potential to greatly decrease system costs, including active and reactive power control and load balancing. While storage is given as an example here, opening markets to enhance system value will create similar opportunities for other technologies as well."[31]

While the rise of storage, of which battery is one option, is therefore part of the rationale for the proposed reforms, it is only one of many factors that justify the adoption of the proposed changes.

The Commission concluded its analysis of challenges and opportunities with powerful rhetoric as follows:

"Utilities, and this Commission, could respond to these challenges by clinging to the traditional business model for as long as possible, relying on protective tariffs, regulatory delay, and other defenses against innovation. A variation on this approach would be to assume a reactive posture, addressing issues only when they have grown into critical or highly visible problems. Alternatively, we can identify and build regulatory, utility and market models that create new value for consumers and support market entrants and this new form of intermodal competition – in other words, embrace the changes that are shaking the traditional system and turn them to New York's economic and environmental advantage.

[31] State of New York Public Service Commission (2015) Page 21

We decisively take the latter approach. For a century, policy goals were adequately served by regulatory methods that encouraged a static and unidirectional model of utility service. In the modern economy, the goals of reliable, affordable and clean electric service will not change; but the methods of achieving them must. REV is both an opportunity to improve greatly on the status quo, and a response to a convergence of trends that make business as usual unsustainable in the long run. The challenges that force us to question traditional methods and assumptions also reveal a pathway toward a more efficient, customer-friendly and sustainable model.[32]"

5.3.2 Description of the proposed changes

The NYPSC describes the "functional center" of the "REV framework" as the distributed system platform provider (DSP).[33]

Three core functions of the DSP are identified:

- to plan the electricity distribution system;
- to operate the physical distribution network; and
- to operate the markets that encourage the adoption of DERs.

Broadly we understand this to be roughly what would be understood in Australia as an independent power system operator with authority also to plan and operate the distribution networks and also to operate markets. The existing distributors will, however, continue to own the distribution network (unlike independent system operators).

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[32] Ibid. page 30.

[33] A working group formed by the Commission defined DSP as "*an intelligent network platform that will provide safe, reliable and efficient electric services by integrating diverse resources to meet customers' and society's evolving needs. The DSP fosters broad market activity that monetizes system and social values, by enabling active customer and third party engagement that is aligned with the wholesale market and bulk power system.*" Ibid, page 31

Under NYPSC's staff's proposal, the DSP will be regulated by the NYPSC, both in its new capacity as a market maker and system coordinator, and in its traditional function as distribution utility. The DSPs will be regulated by the NYPSC. DSPs, it envisages, will "*enable markets, ensure fair market practices, fair and transparent information, data and services to all providers and their customers, impose standards for business practices and other protections necessary to protect consumer interests, and ensure the continued reliability of the system*".[34]

The NYPSC helps to define the DSP model by comparing it to the current arrangements, as follows:

"Under the current regulatory regime, the deployment of Distributed Energy Resources (DER) can be viewed as intermodal competition to the grid itself, threatening to undermine and strand investments made in the traditional system. Under the policy and regulatory principles of REV, DER becomes a tool to reduce system investment needs, and the investments that are made will be consistent with the extensive deployment of DER and therefore much less susceptible to being stranded by market developments. Utilities will have both the obligation and the incentive to support the use of DER as an instrument that will help fulfill their obligations to end use customers while supporting the economic vitality of their new business model. Thus, under our definition of the DSP, DER providers will be viewed as customers and partners, rather than competitors, of traditional grid services.

The recognition that DER providers are customers and economic partners with the DSP represents a significant change to the structure of the retail market. The DSP will have the responsibility to offer services whether in the form of information, interconnection or dispatch services at prices and under terms allowed by the Commission. At the same time, because of the value that they provide to the grid, DER providers and their customers are entitled to compensation from the DSP. This transactive relationship expands the value of the system and is central to a changing relationship wherein the traditional utility and end use customers

[34] Ibid, page 31.

welcome DER as a mechanism to enhance economic and environmental value through a fully integrated grid."[35]

The NYPSC has also identified changes to economic regulation "ratemaking practices" will be critical to the success of the REV vision:

"Under current ratemaking, utilities have little or no incentive to enable markets and third parties in creating value for customers. Rather, utilities' earnings are tied primarily to their ability to increase their own capital investments, and secondarily to their ability to cut operating costs, even at the expense of customer value. Utility earnings should depend more on creating value for customers and achieving policy objectives. Rather than simply building infrastructure, utilities could find earning opportunities in enhanced performance and in transactional revenues."[36]

5.3.3 Implementation

The "REV" debate in New York State is, at the time of writing, a little over two years in development. In its February 2015 Order, the NYPSC set out an implementation plan. Near term actions (that are being implemented at time of writing) include requiring the major New York State utilities to file Distributed System Implementation Plans. A number of other utilities were given a little longer to file these plans. The Orders say that "*Implementation of REV will take years and will involve substantial party participation*."[37]

There are many working groups that are working on aspects of the implementation of the "REV" vision. For an indication of this, we have copied (in Box 2) the implementation schedule, specified in the NYPSC's February 2015 orders:

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[35] Ibid, page 41.

[36] Ibid, page 12.

[37] Ibid page 130

Box 2. New York State Implementation plan

The following schedule will apply to REV implementation matters addressed in this Order:[125]

- March 26, 2015: The Market Design Platform Technology group files its work plan.
- April 1, 2015: Staff initiates process to refine utility codes of conduct.
- May 1, 2015: Each utility identifies one or more potential non-wires-alternative projects.
- May 1, 2015: Parties file comments related to microgrids.
- May 1, 2015: Staff files guidance for ETIPs.
- May 1, 2015: Staff issues a proposed Benefit Cost framework.
- June 1: 2015: Staff issues a Straw Proposal related to Track Two ratemaking issues.
- June 1, 2015: Staff issues a large scale renewable options paper.
- July 1, 2015: Staff issues a Consumer Protection proposal.
- July 1, 2015: Each utility files a status report regarding interconnection process improvements.
- July 1, 2015: Each utility files demonstration projects.
- July 1, 2015: The Market Design Platform Technology group reports.
- July 15, 2015: Each utility files an ETIP.
- August 3, 2015: Staff issues guidance for Distributed System Implementation Plans.
- September 1, 2015: Staff reports to the Commission regarding distributed generation emission rules.
- September 1, 2015: Staff reports to the Commission regarding billing initiatives.
- December 15, 2015: Each utility files an initial Distributed System Implementation Plan.

The New York State "REV" is clearly a very ambitious and major reform. No doubt it will become clearer in due course.

6 Options for NSP involvement in grid-connected battery storage

This penultimate section describes and discusses potential options for the involvement of network service providers in grid-scale, grid-connected battery storage. It builds on the discussion of principles (in Section 2), the description of storage and survey of storage economics (Sections 3 and 4) and the review of experience in other countries (Section 5).

The section describes and discusses six possible options plus the NYC option. Many more options could be identified, but we have suggested these six sufficiently distinct options as a starting point. The options cover a spectrum at the one end of which NSPs have a complete monopoly over the development, ownership and operation of grid-connected batteries and recover their investment in batteries as they would for other network assets (such as transformers). At the other end of the spectrum, NSPs are precluded from including batteries in their regulated asset bases and thus recovering their investment through regulated charges. A summary of the options is set out in Figure 19 below:

Figure 19. Options for NSP involvement in grid-connected battery storage

NSP complete monopoly

NSP competes with others in unregulated market

Option	1	2	3	4	5	6	7
Description	NSP Monopoly	Inclusion in RAB but not Monopoly	Ceiling on inclusion in RAB	Ceiling and network benefit only inclusion in RAB	Technology agnostic procurement	No RAB inclusion	Split operation from ownership
NSP Monopoly	Yes	No	No	No	No	No	No
Inclusion in NSP RAB	Full	Full	Full	Partial	None	None	None
Third Party Involvement	No	Maybe	Yes	Maybe	Yes	Yes	Yes

6.1 Option 1: NSPs have regulated monopoly

With this option, NSPs have a monopoly in planning, developing, owning and operating grid-connected batteries that provide a shared service to the grid. In this respect a grid-connected battery would be treated in the same way as transformers or power poles.

This does not mean that parties other than NSPs can not own or operate batteries, just as significant transformer capacity is currently owned by parties other than NSPs. However, in principle all batteries that are connected to the grid in front of the customers' meter and which provide shared services will, with this option, be a monopoly of the NSPs.

As with other network expenditure, expenditure by NSPs on batteries could be subject to various forms of regulatory controls including investment tests. Incentives to encourage efficiency may exist as a consequence of the regulatory design adopted. Assuming the current five yearly controls exist, NSPs would possibly have an incentive to reduce expenditure below regulatory allowances.

As discussed in the previous sections, there are currently two examples of grid-connected battery storage systems developed by NSPs in Australia. In both cases they are included in the regulated asset base and their investment will be recovered through regulated charges.

6.1.1 Arguments for this option

Dominance of network benefit

As discussed throughout this paper, grid connected batteries may provide both network benefits (mainly the ability to defer or avoid augmentation of the shared network and the ability to store electricity when it has a low value and produce it when it has a high value). Depending on the circumstances, it might be the case that the bulk of the value of a battery is the benefit it provides to the network. If this is the case, it might be argued that NSPs should have a monopoly in respect of battery provision just as they do in respect of the ownership and operation of poles, wires and substations that provide shared services.

Avoiding co-ordination costs

It might be argued that allowing NSPs to monopolise grid-connected batteries would minimise co-ordination costs. Such co-ordination costs might arise where third parties that might own and operate batteries would need to co-ordinate the development and operation of a battery with the NSP whose network they connect to. Such co-ordination might be expected in development (for example finding suitable sites, physically connecting to the network) and operation (co-ordinating the operation of the battery by a third party within a network whose other assets are operated by the NSP).

Avoiding transaction costs

Transaction costs will be incurred if NSPs are to procure network support from third parties. Specifying contracts for the purchase of capacity from a battery operator may prove to be complex, just as it is for the procurement of demand response. Such costs could be avoided if the NSP owned and operated the battery (it does not need to contract with itself).

Information asymmetry

It might be argued that network operators have access to better knowledge about the network and network costs than third parties that are not specialised in network engineering and do not operate the network. Accordingly, network operators, it might be argued, would be much better placed to determine where batteries would be valuable, and would be much better placed to understand the relative economics of batteries versus alternative network solutions.

Security of supply

It might be argued that network providers will prefer to own and operate infrastructure than to procure services from others on the basis that they feel that they can rely on assets that they own and operate, and will be less confident in assets that they don't own and operate, although in principle such assets might provide equivalent services. On this argument extending the monopoly to batteries is needed to ensure NSPs feel able to treat them in the same way as other solutions that they do have monopoly rights over.

Natural monopoly

It might be argued that a grid scale battery shares many attributes with the other main elements of grid infrastructure: lumpy capacity increments and marginal costs that are much lower than average costs. It is for these reasons that network provision (by conventional means of poles and wires) is often referred to as the quintessential natural monopoly. If indeed the cost structure and lumpiness of grid scale batteries is similar to that of other network elements, then the argument for natural monopoly would apply to grid-scale batteries as well.

6.1.2 Arguments against this option

There are counters to the arguments set out above, as follows:

Network benefit may not always dominate and even if it does, it does not matter: Even if the greatest proportion of the value of a grid connected battery is a network service, this does not justify monopoly provision. In addition, there may be circumstances where consumers or market participants may choose to invest in larger batteries connected to the grid and to make this storage available to consumers, rather than providing storage at the point of use. Granting NSPs a monopoly in storage would preclude such investment.

Co-ordination costs are unlikely to be significant: Are these costs necessarily substantial? Connection to transmission and distribution networks has been contestable for many years. Why would the connection of grid-scale batteries be any more difficult to co-ordinate, than the connection of demands and generators?

Transaction costs may not be significant: Depending on the contract form, transaction costs could be an issue. However, based on the limited experience to-date is there reason to believe that they are necessarily significant?

Information asymmetry: This may be a significant issue: if information on the optimum location of a grid-connected batteries (from a network service providers' perspective) is not publicly available, battery developers other than NSPs will be disadvantaged in their ability to realise network benefits. This will undermine one of the main benefits that batteries offer. But surely the solution here is to address the information asymmetry through regulation of the dissemination of data, rather than simply falling back on monopoly.

Security of supply: If an NSP feels that it can not rely on services provided by batteries that are owned by others, it may not be inclined to procure the services of such batteries from third parties, and may instead develop more expensive alternatives. But an NSP does not need to have a monopoly over grid-connected batteries in order to achieve such security: if it can develop and own the batteries itself even if it does not have a monopoly it can obtain the security it requires.

Natural monopoly: batteries may have substantial upfront costs but unlike poles and transformers (which do not need to be re-charged) on-going expenditure is needed to ensure batteries are available to provide the services for which it could substitute for network elements. They are also unlikely to exhibit the lumpiness and scale economy evident in poles and transformers where power capacity rises as the square of voltage or current.

Summary

The natural monopoly, co-ordination cost, network benefit and security of supply arguments in favour of monopoly are not convincing. On the other hand, transaction cost and information asymmetry are concerns that need to be addressed. Both of these can probably be dealt with effectively through regulation of the access to information. In addition, the argument that monopoly will stifle innovation and incentives to efficiency is as valid a concern in relation to batteries as it is in any other industry. Accordingly, we conclude unequivocally that there is no convincing reason to grant NSPs a monopoly in the ownership and operation of grid-connected batteries.

6.2 Option 2: NSPs may include batteries in the RAB

This option is a variant of the first, but in which parties other than the NSP may also own and operate batteries. NSPs would not be obliged to procure network services from other grid-connected battery owners, but may procure network services if they choose to.

The argument for this option is that allowing other parties to develop and operate batteries means that they are not deprived of the benefits provided by batteries. The other argument for this option is that battery developers that have no interest in providing network services (seeking revenue from their batteries solely through their ability to store electricity and provide this service to market participants) will be free to develop batteries and connect them to the network (subject to the usual environmental, safety, planning and technical regulations).

The argument against this option is that simply allowing parties other than NSPs to own and operate batteries is no guarantee that there will be a fair competition between the network service provider and other party in providing batteries. In addition, allowing others to develop batteries does not of itself provide competition with NSP's own development of batteries to be included in their RAB (because batteries owned by third parties can not be included in the NSPs' RABs). There may be persistent concerns that NSPs' access to network information not available to other market participants and the fact that assets included in the RAB will not be exposed to stranding risk, is likely to mean that NSPs can crowd-out competing battery developers.

Regulation will be needed to address such competition concerns. But there must be doubt that regulation can be an adequate response to such concerns. Indeed, the argument would surely be that if regulation is able to protect crowding out in the development of batteries by NSPs, then we might expected that regulation could be successful in preventing crowding out if NSPs owned and operated power stations. This argument is unequivocally rejected in the case of NSP ownership of generation and surely should be rejected in the case of NSP ownership of batteries, for the same reasons. Therefore, we do not think it would be sensible to rely on regulation to protect against crowding out and so reject this option.

6.3 Option 3: NSPs limited to share of all battery capacity in the RAB

This option is a variant of the previous option but there will be a percentage limit on the battery capacity that can be owned by the NSP and included in its RAB. This is essentially the model that has been adopted in California so that the regulated entities may not own more than half of all the capacity need to meet its mandated storage targets.

The advantage of this option, relative to Option 2 is that it deals, to some extent, with concerns about crowding out by mandating that a certain percentage of all grid-connected battery storage is not owned by the NSPs.

As we noted in the section on the arrangements in California, the regulated utilities in California opposed this approach on the basis that unless they owned the grid-connected battery they would not be inclined to rely on it for network services. The CPUC rejected this argument on the basis that[38]:

"there is room to allow for different types of economic or policy driven storage projects that meet different needs, cost requirements, and other criteria … utilities may own no more than half of all of the storage projects they propose to count toward the MW target, regardless of whether it is interconnected at the transmission or distribution level, or on the customer side of the meter. We believe that setting this limit will ensure that any viable market options are not preempted. "

This option has merit in the context of binding storage development targets, as in California where the obligation to meet a target and to procure half of the target from third parties creates a market for third party storage development. The approach may not be successful in the context in which NSPs have no binding storage development target – they may simply avoid developing or procuring battery capacity if the choice is between developing network infrastructure that they own and control or procuring

[38] California Public Utilities Commission (2013)

battery capacity that they don't own and may not control. Accordingly, in the absence of mandated storage targets, we reject this option.

6.4 Option 4: Part of battery that provides network benefits included in RAB

With this Option, NSPs may only include in their RAB, the portion of the outlay in a grid connected battery that is calculated to be responsible for the provision of network services.

A variant of this option (Option 4a) might be an extension of Option 3 that would limit NSPs to include a maximum percentage of all storage capacity in the RAB and of which only the portion calculated to provide network services would be allowed.

Of course one part of a battery does not provide network services and the other part energy arbitrage, the two services come from a single battery. Only allowing part of the outlay in a battery to be capitalised in the RAB will rely on a calculation to split the benefits between energy and network and from this to proportionally split the outlay.

In principle, this option will encourage NSP battery developers to partner with market participants so that the participants that obtain the energy market benefits (the opportunity to arbitrage between low and high priced periods) contribute to the capital outlay. Alternatively, if such partners can not be found, the NSP proposing to develop a grid scale battery would need to fund the full cost of the battery but would only be eligible to include the proportion calculated to provide network benefits into the RAB.

Regulatory arrangements would need to be developed to specify and enforce the relevant calculations.

The main argument for this approach is that consumers will not bear the risk that energy arbitrage benefits fall short of the outlay (that they would otherwise be charged for if the whole battery was included in the RAB). Instead this risk will be borne by the market participant that partners with the NSP to develop the battery and thereby acquires the rights to the energy market benefits.

The main argument against this approach is that if it proves to be difficult for NSPs to form partnerships there may be inefficient under-investment in batteries and if this is the case then consumers would be relatively worse-off since more expensive alternatives may be developed and consumers charged for this through regulated charges.

On balance, requiring NSPs to partner with market participants for them to fund the portion of a battery that provides market benefits is, we suggest, a reasonable requirement. It will mean that investors, rather than consumers, bear the risk that energy market benefits fall short of expectations. It will reduce the quantum of investment recovered through regulated charges and will force NSPs to partner with commercial organisations in battery development. This is likely to bring valuable skills and disciplines to the development of batteries. Accordingly, we commend this option for further consideration.

6.5 Option 5: NSPs restricted to technology-agnostic procurement

This option is akin to the approach implemented in Scotland where the distributor tendered for "congestion management services" as an alternative to investment in additional distribution lines or building its own battery. They did not specify the technology required to provide the congestion management service but instead set out the congestion management requirements, demand forecast and the grid expansion plan[39].

The successful developer – Scottish and Southern Energy-received payments from the distributor for provision of the congestion management service and was also able to seek income from other commercial activities, such as the provision of ancillary services to National Grid and energy market arbitrage.

[39] Vasconcelos et al. (2012)

The main argument against this approach is that distributors may not feel able to rely on services provided through contract from assets that they do not own or control. We noted that this concern was raised by distributors in California. The CPUC rejected the concern, at least in part, by requiring that half of the targeted battery storage be developed and owned by parties other than the distributor.

There may be ways to promote confidence that NSPs may have in the provision of contracted services. Control may be split from ownership so that even if the NSP does not own the battery it can still control its operation. While control is more easily achieved through ownership, developing appropriate contractual arrangements to achieve control without ownership should not, we would think, be terribly difficult.

One of the other attractions of this approach is that it more obviously introduces competition between batteries and alternative possibilities (such as demand management contracts).

A disadvantage is that this approach will likely require additional regulation to control and enforce technology-agnostic procurement.

On balance, we suggest this approach has much to commend it. But it would be valuable to understand better the likelihood (and reasons) that NSPs would reject the development of procured congestion management services from batteries owned by others, in favour of more expensive conventional network solutions that they can own and include in their regulated asset bases.

6.6 Option 6: NSPs prohibited from including batteries in their RABs

With this option, NSPs will prohibited from including batteries in their RABs. This is similar to the arrangements that apply in respect of generation assets (subject to de-minimus limits), and that also apply to large scale storage assets (pumped hydro) in the NEM. It also applies in respect of connection assets and meters for larger consumers and increasingly also in respect of meters for smaller consumers.

The advantage of this is approach is that it avoids the complexity of regulations that would be needed to protect consumers from regulated development (and also regulation to protect third party battery developers from being crowded out by NSPs undertaking regulated projects). If in fact such regulation is ineffective no matter how complex it becomes, the case for this approach would be strengthened.

The disadvantage with this approach is that procuring congestion management services, as in the Scottish example, may not be seen by Australian NSPs as a suitable substitute for owning and operating batteries. If this is the case, prohibiting NSPs from owning are operating assets may stifle the development of alternatives to more expensive development of poles and wires. This might be described as an approach that cuts off the nose to spite the face.

This disadvantage has to be taken seriously. It would be helpful to understand why NSPs might refuse or be reluctant to procure battery services from others. If their concerns are legitimate this should not necessarily lead to the assumption of NSP monopoly. If their concerns are not legitimate, serious consideration might be given to splitting network planning from asset ownership. In addition, we note that there are limits to the validity of this disadvantage: if batteries become so much cheaper than network alternatives NSPs will find it increasingly difficult to resist the procurement of battery services from others.

6.7 Option 7: Split system operation and planning from asset ownership

This option is, in essence, the changes that have been proposed and are currently in the course of development in New York State. The essence is to separate the planning and operation of the distribution system from its ownership. The closest Australian parallel is the arrangements for the planning and operation of the Victorian transmission network whereby the Australian Energy Market Operator plans the augmentation of the Victorian power system.

Change along these lines in Australia would be momentous. As we noted in the discussion in the prevision section, in New York State these changes have been motivated by trends towards increasing decentralization through distributed generation and technology improvement, including more advanced communications and monitoring infrastructure, web-enabled and centrally controllable appliances. The rise of decentralised and grid-connected battery storage has been part of the motivation for change, but as we noted, not the primary motivation for change.

In New York State these changes originate in a very clearly expressed aim, championed by the Governor, to:

"reorient both the electric industry and the ratemaking paradigm toward a consumer-centered approach that harnesses technology and markets."

The principle advantage of the New York approach is that it adopts a wholistic approach in which the arrangements for battery storage are, correctly, just one part of a bigger whole.

In Australia our political and regulatory system has not set out such clearly expressed reform objectives. It is unlikely that a change as massive as that being developed in New York State can be contemplated in Australia in the absence of the sort of political leadership evident in New York State. For this reason, for the purpose of this report and specifically for the purposes of recommendations confined to the involvement of NSPs in grid-scale batteries, we don't think it is plausible to advance this option as an approach to be evaluated in regulatory fora. However in our opinion the approach adopted in New York is the most thoughtful and broadly considered approach in adapting to the many changes of the demand-side of the industry.

NSP involvement in behind-the-meter storage

The conceptual discussion in this section to this point has focused principally on grid-scale batteries connected in front of customers' meters on the shared network. Should NSPs be allowed to invest in batteries on the customers' premises behind their electrical meters and included this in their regulated asset base? We understand that in Auckland, the local distribution network service provider, Vector, has installed batteries in combination with PV in several households and may have included the assets in their regulated asset base. We understand that this is permissible under de minimus limits applicable in New Zealand. [40]

Historically electricity utilities in Australia have had "behind the meter" involvement with electricity consumers, particularly households, through controlled remote switching of water storage heaters. Such arrangements remain common and have been extended in some cases to other appliances such as air-conditioners.

However, distributor ownership and control of battery storage behind the meter and inclusion of this in its RAB would represent a significant extension of distributor involvement. In the context in which distributor involvement in assets where markets can easily exist – such as meters – is being wound back, it would be a retrograde step to allow NSP involvement in batteries behind the meter, and for this to be included in the RAB. Accordingly we conclude, unequivocally, that NSP should be precluded from behind the meter battery ownership.

However we see no reason why they should be precluded from procuring network services from behind-the-meter batteries owned by the end users or third parties.

6.8 Subsidiary regulatory issues

The terms of reference of this study includes recommending:

- What investment test, if any, should apply to NSP investment in distributed storage including grid-scale storage?
- Should NSP involvement in distributed generation and storage including grid scale storage be regulated through standard control services or some other form of alternative control service?

[40] Personal communication, New Zealand Commerce Commission.

Investment test

A regulatory investment test applies to capital projects in distribution networks greater than \$5m. We are skeptical about the effectiveness of such regulatory tests in protecting consumers' interests. Evidently in both transmission networks, asset-specific investment tests have been ineffective in preventing the substantial capacity surpluses discussed earlier in this report.

It is tempting to suggest that an investment test can be developed and that this will be effective in protecting consumers from inefficient investment. This temptation should be resisted. Instead, if NSPs are to be allowed to include batteries in their RAB we suggest that effort be directed at ensuring that information on such projects such as capacity, capital outlays and operating costs and treatment of non-network revenue is publicly and easily available.

Standard control services or other form of control

Standard control services apply to investments included in the RAB. It might be possible to conceive of various forms of asset-specific regulatory control that would involve partial inclusion in the asset base. Where battery services may be procured through contract (such as Orkney's "congestion management service") such amounts would need to be included in regulatory allowances for operating expenditure. Such asset-specific regulatory incentives would, we expect, be contemplated as part of the AER's standard control service regime. In line with the analysis of the various options in this section, we suggest, however, that the focus should be on facilitating the development of batteries preferably through arrangements that do not involve inclusion of the assets within the RAB.

7 Recommendations

The scope of this report covers network service provider involvement in grid-connected and distributed batteries. We restrict our recommendations to this. However, we would like to draw attention to the arrangements currently being implemented in New York State. These arrangements seem be to the most comprehensive and wholistic consideration of the many issues shaping the development of distributed electricity markets. We urge regulators, policy makers and politicians to carefully examine their proposals.

Our specific recommendations relating to network service provider involvement in batteries are as follows:

Recommendation 1: NSPs should be allowed to develop unregulated businesses for provision of grid-connected and behind-the-meter storage. But in preparation for this it would be valuable to carefully examine the arrangements for ring-fencing of regulated activities from unregulated activities and, where applicable, the arrangements for ring-fencing networks from retail activities. It would also be valuable to examine the nature of the relation that network service providers have with end users to ensure that by virtue of this relationship they are not able to obtain and unfair competitive advantage in the development of grid-connected and behind-the-meter batteries.

Recommendation 2: With respect to grid-connected batteries, we recommend for further detailed examination:

- Option 4 and 4a (only the part of the battery that provides network benefits can be included in the RAB).
- Option 5 (NSPs subject to technology-agnostic procurement and requirement to procure as much battery capacity as it owns).
- Option 6 (NSPs not allowed to include grid-connected batteries in RAB).

Recommendation 3: In the context of very rapid technology development, regulatory arrangements for NSP involvement in batteries must be adaptable to change.

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