SMALL CONSUMER GROUPS' POSITION PAPER

SEPTEMBER 2016

This project was funded by Energy Consumers Australia (www.energyconsumersaustralia.com.au) as part of its grants process for consumer advocacy projects and research projects for the benefit of consumers of electricity and natural gas. The views expressed in this document do not necessarily reflect the views of Energy Consumers Australia.

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SUMMARY

In response to the burgeoning of both consumer-side and grid-side energy storage in the NEM and the lack of regulatory clarity around how storage should be treated, this paper has been prepared to help guide small consumer groups in developing policy positions they can take into regulatory review processes.

Its main focus is on the extent to which networks should be able to own batteries on both sides of the customer's meter. Consistent with the long term interest of consumers, we identify three objectives for this review: *reducing risk to consumers, increasing competition* and *supporting electricity sector decarbonisation.*

In relation to consumer-side storage, we agree with the Australian Energy Market Commission (AEMC) that storage should be regarded as a contestable service and that networks should only be able to own batteries through ring-fenced businesses.

Drawing on the work of Mountain (2015) as well as international comparisons and following consultations with small consumer advocates and other stakeholders, this paper considers three options for regulating grid-side storage. Our preferred position is Option 3, *All opex, no RAB* (regulated asset base)**.** That is, battery services should be classified as unregulated. As well as best conforming to our three objectives, this option is arguably the simplest and clearest, with the lowest long term administrative and regulatory burdens.

We canvass two options for implementing the *All opex, no RAB* solution. Under Implementation Option 3.1, all services potentially provided by grid-side batteries that are currently classified as network services (identified in Appendix 3 as relating to *managing peak demand, supporting isolated feeders* and *providing power system security*) should in future be classified as *Distribution - Unregulated* and therefore contestable – that is, whether they are procured via batteries or via traditional network augmentation.

Alternately, under Implementation Option 3.2, *energy storage services* would be separately defined (akin to metering and connection services) in the rules, and then required to be unregulated in the framework and approach (F&A) process. To implement this option, a rule change will probably be necessary to separately define energy storage services. Both implementation options will result in battery services being procured as opex.

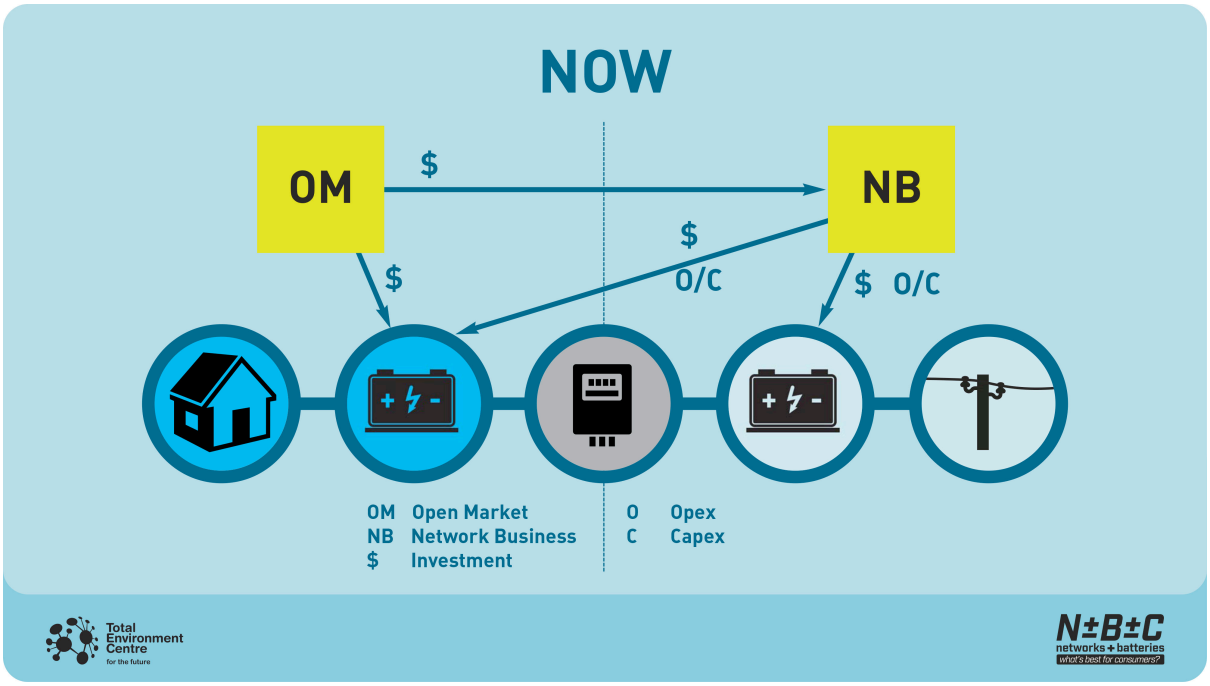
We see no evidence to date that our preferred approach will dampen the uptake of grid-side storage, even in fringe of grid locations, although there may need to be an exemptions framework in place for a limited time to cater for such scenarios.

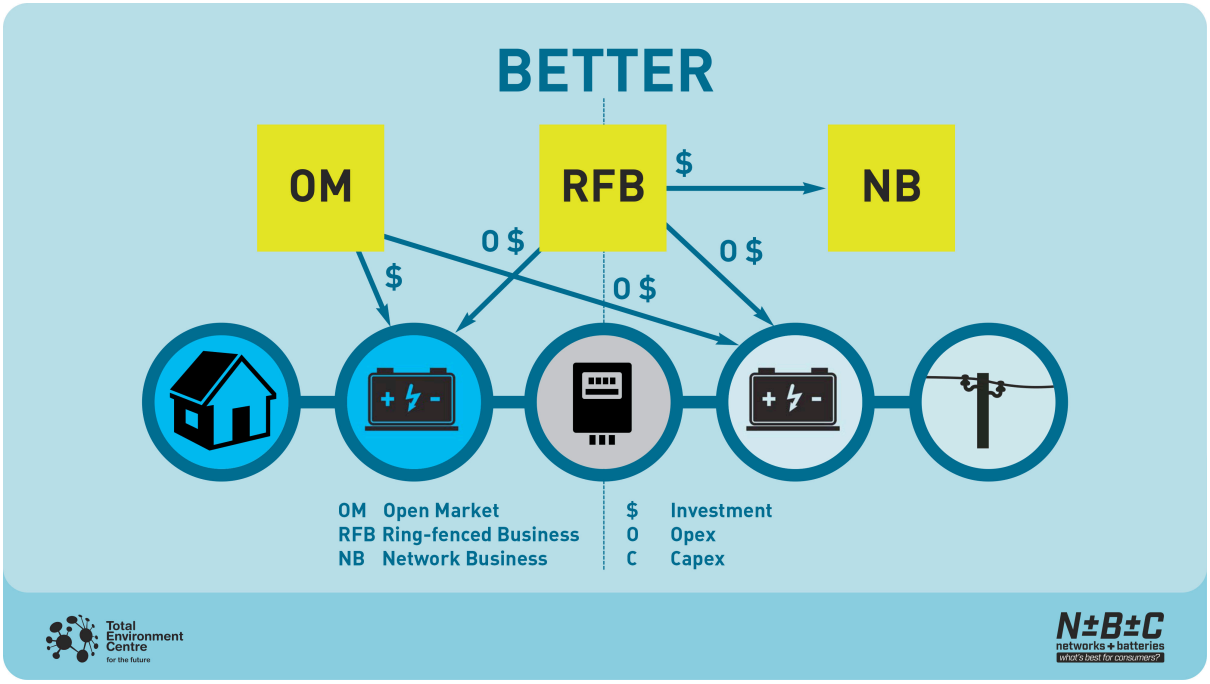
We also make a number of other recommendations relating to such matters as the AER's ring-fencing guideline, reviewing capex-opex incentives and the need for a thorough overhaul of the morass of service classification, cost allocation and shared asset regimes to make them more dynamic and accessible to proponents of new products and services. It may also be time to consider the Ofgem solution of capitalising capex and opex equally under a "totex" model.

This paper may undergo further revision and refinement as various regulatory processes unfold.

The two infographics on the next page summarise our understanding of the status quo and our preferred position, with the arrows and $ symbols indicating potential investments.

INFOGRAPHICS





1. INTRODUCTION

> Utility regulation should perform the functions that competition would otherwise play in a market, e.g., management of entry, setting efficient prices, and prescribing quality and conditions of service. Regulatory models need to evolve in response to competitive advances and challenges presented by the digital economy.[1]

This draft position paper has been prepared by Total Environment Centre (TEC) pursuant to a grant from Energy Consumers Australia (ECA) entitled *Networks + Batteries: What's best for consumers?* The objective of this project is *to promote regulatory reform that encourages the rollout of energy storage consistent with the long term interests of consumers.*

TEC's primary interest is in improving the environmental outcomes of the National Electricity Market (NEM), the marketplace for the dirtiest – most carbon-polluting – industry in Australia. TEC is keen to promote the rollout of consumer- and grid-side batteries (or energy storage)[2] on the assumption that it will be used primarily to store renewable energy, especially to manage peak load on the consumer side by storing rooftop solar energy and to manage the intermittency of wind and solar farms on the grid side.

However, there are other benefits from batteries, some of which do not necessarily involve the storage of renewable energy. There are, on the other hand, various risks associated with the rollout of batteries on both sides of the customer's meter. This emerging market is therefore of interest to a wide range of energy consumer organisations. To save each group having to develop a policy position individually in relation to a range of complex regulatory challenges, ECA funded TEC to develop a position paper that would inform those of other groups, most of which lack the resources to individually analyse the regulatory issues in detail.

In this project we have consulted widely – including informally with some networks – and have sought to develop a policy position in relation to the involvement of networks in the battery market with which other small consumer advocacy organisations could be in accord. To that end, the project includes a reference group consisting mostly of other members of the National Energy Consumers Roundtable.[3] A draft position paper was circulated to the Reference Group and selected others[4] for discussion and feedback before being finalised.

The views expressed in this paper represent those of the organisations whose logos appear on the title page. The position adopted is intended to be potentially applied, with further developments, in various forthcoming regulatory reviews and reforms by these organisations signatories. However, they are not bound by the recommendations herein and may proffer different views in future.

Our focus is primarily on the role of distribution networks in this process, but the recommended regulatory option for grid-side batteries could apply to transmission networks as well.

1.1 Setting the scene

Thanks to a combination of the recent solar revolution, high (and increasing) retail electricity prices and an affluent society, Australia is, we are often told, the canary in the coalmine or the guinea pig in relation to the emerging market for energy storage. At present the NEM is almost a Wild West for batteries; not only are safety standards and consumer protections struggling to keep pace with the market, but there seem to be few limits to who can install, own or control batteries on either side of the meter.

Networks are currently doing small scale trials on both sides of the meter – some using demand management incentive scheme (DMIA) funds, others relying on leftover opex revenue – to test technical compatibility, business models, consumer acceptance, tariff options and ancillary services. They are installing grid-side units on the end of long feeder lines to manage peak demand and potentially reduce future capex needs. They are partnering with property developers or local

communities to install batteries on microgrids to share local energy. They are exploring large grid-side units to balance the flows from multiple wind farms.

This is not a complete list. Wholesale price arbitraging (charging batteries when the wholesale market price is low, exporting it when prices are high) possibilities are being explored by various parties as part of the economic justification for battery projects. Every month sees at least one new project in most jurisdictions (with NSW being a recent laggard after some early trials) for novel project types. While two networks (Ergon and Energex) have been granted ring-fencing exemptions from the AER for their battery projects,[5] we are not aware that the AER has any serious concerns about the lawfulness of any of these projects; so we must conclude that at present, there are few limits to what networks either are allowed to do with batteries, in respect of either ownership or control, on either side of the meter.[6]

From a consumer advocacy perspective, we welcome the embrace by most networks of this new technology, which in combination with the solar revolution promises to transform the energy sector in coming years and decades, offering consumers more choice and control and eventually cheaper and cleaner energy. The extensive rollout of batteries is critical to the shift to both a decentralised energy system and a decarbonised economy.

But we also have concerns. While the plethora of current project types will certainly help networks to assess the technical requirements of different technologies and to develop new business models in the wake of recent and projected falling peak demand and total consumption, few would want to see a repeat of the situation that developed between 2008 and 2015, when (for a variety of reasons) networks were allowed to spend some $45 billion on new poles and wires, all with an average regulatory lifespan of around 30 years, leading to an increase in retail prices of some 70 per cent in NSW and Queensland in particular and (given the "roll forward" model for assets in revenue determinations) the certainty of future high prices.

To put it crudely, the rollout of batteries must be done in such a way as to dissuade or prevent networks from going on another spending spree. We don't want customers to bear the inherent risks from investing in battery technology by paying the costs without necessarily receiving the benefits. The investment risk needs to be properly shared. At the moment, with most projects being funded through the DMIA or by ARENA, the risk is being borne mostly by consumers and taxpayers. If future projects are funded through capex and added to RABs with regulated returns (likely for at least 10 years),[7] the investment risk of these investments by networks may be being borne mainly by electricity consumers. This can lead to poor incentives to deliver the expected benefits.

The fundamental conceptual challenge is to strike a balance between, on the one hand, creating a high level of competition in the market, in the expectation that this is more likely to lead to good consumer outcomes than control by monopolies (see 2.1 below); and on the other hand, knobbling networks to such an extent that they exit, or do not enter, this market at all on either side of the meter, and potentially make life difficult for other parties to do so.

That is the conundrum which this paper seeks to address. As such, it is not directly concerned with related issues such as safety, consumer protections or environmental sustainability in relation to the battery market in Australia. For practical reasons, neither does it discuss in detail the issue of the control of batteries independent of ownership. (For instance, could networks exercise undue power on the battery market without even owning them – e.g., via direct load control [DLC] devices?)

The remainder of this section discusses pivotal background documents and market changes in the last year.

1.2 Mountain (2015)

This paper follows closely from a 2015 report by Bruce Mountain for the Public Interest Advocacy Centre (PIAC) entitled *Batteries and electricity network service providers in Australia: regulatory implications.* That report sought to answer the question of

> …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.[8]

In relation to grid-side batteries, Mountain identified

> …seven possible options for network service provider involvement in batteries… 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.[9]

He recommended that some of these options be rejected and some others be subjected to further examination. He found that Option 7, the separation of operation from ownership, effectively preventing networks from owning batteries and including them in their RABs, to be "the most comprehensive and thoughtful approach to the issue", but that "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."[10]

Mountain also addressed the issue of network ownership of consumer-side (or behind the meter) batteries. Like most regulators and industry stakeholders (other than networks themselves) around the world, he concluded that networks should "be barred from the ownership of batteries that are located behind the customer's meter", but that they should "be allowed to develop unregulated businesses for provision of grid- connected and behind-the-meter storage."[11] To deal with the potential conflicts of interest that can occur between such related businesses, he also recommended careful examination of ring-fencing arrangements to ensure that networks "are not able to obtain an unfair competitive advantage in the development of grid-connected and behind-the-meter batteries."[12]

1.3 AEMC Integration of storage report

Two important developments have occurred in the world of battery regulation in the NEM since 2015. The first was the release of the AEMC's Integration of Storage final report.[13] Essentially, the AEMC found that "the functions [battery storage] performs are not different to other types of technology and can be accommodated within the existing regulatory frameworks."[14] In light of its preference for technological neutrality, a competitive market framework, the promotion of consumer choice and the creation of a level playing field for market participants, the AEMC concluded that

> …storage should be considered a contestable service… Network businesses should only be allowed to own storage behind the meter through an effectively ring-fenced affiliate that separates this activity from the provision of regulated network services.[15]

In other words, networks should not be able to own consumer-side batteries, because this would inhibit the development of a competitive market; they may, however, play in that space via related but ring-fenced businesses.

In relation to grid-side batteries, the AEMC concluded that "Storage used to provide services on the network would be subject to the AER's usual service classification."[16] That is, where the AER determines that a grid-side network service (such as arbitraging or ancillary services) should be contestable or competitive, the network could only provide it via batteries through the open market or a ring-fenced entity. Conversely, for a service such as augmentation capex to meet peak demand

that the AER deems to be a regulated network service, the network could provide it directly through batteries. It would then be entitled to add the value of the assets providing these regulated services to its asset base.

The situation obviously becomes more complex in relation to the multiple value streams offered by batteries, in which case some would be regulated and some unregulated or contestable; the challenge then is how to ensure the balance is maintained over time, as different value streams wax and wane.

Finally, the AEMC proposed a broad work program to implement its recommendations, including

- Clarifying the boundaries of services that can be provided by a DNSP in its capacity as a regulated entity.
- Clarifying service classification definitions.
- If necessary, imposing cross-ownership restrictions on network businesses.
- The need for the AER to develop a robust ring-fencing guideline.

The AEMC also highlighted the need to review the effectiveness of incentives for networks to invest in capex (their historical preference) versus opex, since this would impact on their willingness to invest in batteries via third parties as opex rather than adding them to their asset bases as capex; and lead times and thresholds in the network planning process, especially in light of the scale, flexibility and lifespan of batteries vis-à-vis traditionally more "lumpy" and expensive kit.

1.4 AER Ring-fencing guideline

As a consequence of the AEMC's Power of Choice reforms, the AER is required to publish a NEM-wide ring-fencing guideline to replace the jurisdictional guidelines in operation since 2008. As it explains in the Preliminary Positions Paper,

> To date ring-fencing has been largely focused on separating regulated network services (poles and wires) from contestable services (electricity retail and generation). Now we are looking at its applicability more broadly to all contestable services, including metering, connection and decentralised energy resources, such as energy storage services.[17]

The AER process has served to focus the attention of consumer and other stakeholders on the implications of different models of distribution network ownership or control of batteries. Whether on the consumer-side or the grid-side, the choice is between outright network ownership, prohibition of network ownership, or network involvement via a mixture of direct ownership and indirect ownership via ring-fenced entities.

In its Preliminary Positions Paper, the AER took the view that it should tie ring-fencing obligations to the classification of network services. In practice, this means that contestable services are likely to be subject to ring-fencing, while regulated network services are not. For example,

> In the circumstance where an NSP uses DER to offer a service into a competitive market, such as the wholesale market for electricity, the service would not be classified as a direct control service and therefore would be ring-fenced under the approach proposed in this paper.
>
> Alternatively, if a DER device was used exclusively as an input to providing standard control network services, for example, to smooth demand peaks thereby mitigating network augmentation, then no ring-fencing would apply in relation to the function provided by this device. This is because the device is being used exclusively as an input to the provision of a regulated standard control network service.[18]

The problem arises, of course, where batteries provide multiple services, some regulated, some not; even more so where the battery is installed primarily to provide a regulated network service such as managing peak demand, and is added to the RAB on that basis, but becomes increasingly valuable for its role in energy arbitraging. If a network or its ring-fenced affiliate obtains the benefit from

arbitraging, is it fair that consumers should continue paying for the regulated asset; and if not, how do we ensure there is a mechanism for correcting the return on unregulated returns from regulated assets on an annual or five yearly basis? In theory such a mechanism already exists,[19] but its effectiveness in relation to batteries is untested, with Ergon and Energex choosing instead to apply for ring-fencing exemptions.

The most obvious alternative to ring-fencing is structural separation – that is, a step beyond "legal, accounting and functional separation, along with restrictions around information flows and staff sharing" to the creation of an entirely separate business (although they may still share the same owner/s). While this would appear to confer advantages from a consumer perspective, since it makes it less likely that the regulated business could favour its affiliate, there are downsides – not least the fact that, under the current Rules, the AER is not able to demand structural separation.

1.5 ENA/CSIRO Network Transformation Roadmap

Building on the CSIRO Energy Futures Forum process and 2013 final report, in 2015 and 2016 the Energy Networks Association (ENA) has been working with CSIRO and industry and consumer participants to "to identify the preferred transition which the electricity network industry must make in the next decade, to be ready to support better customer outcomes under a diverse range of long-term energy scenarios."[20] As part of this process, in August 2016 the ENA and CSIRO commissioned a report by Cambridge Economic Policy Associates (CEPA) to recommend "regulatory options and pathways for Australian electricity networks so that customers can get the best value from changes in technology and services."[21]

The CEPA report directly addresses the issue of who should own and control consumer- and grid-side batteries. It is based on case studies on how regulatory reform is happening in response to technological and market changes in Australia relative to other jurisdictions with some similar characteristics: California, New York and the UK. After reviewing these case studies, CEPA makes the a number of pertinent observations which are quoted in Appendix A.[22] These lessons broadly support the adoption of either our Option 2 or 3 (see Section 4 below); but the lesson is also clear that the more battery investment occurs through opex, the greater the risk is balanced between networks, third parties and consumers (relative to allowing networks unfettered ownership rights to batteries, with regulated returns through RABs). This conclusion is reinforced by CEPA's subsequent acknowledgements that some storage and related services previously considered non-contestable may now be contestable, and applies even more so when the changing economics of going offgrid mean that networks cannot be considered to be the only potential providers of these services.[23]

The CEPA report goes on to recommend a series of high-level tests to determine whether a service should be regulated or contestable, and a "competition test" to determine which services should fall into which category. While this is a logical and useful exercise, it would need much more discussion work and rule changes in order to be implemented in the NEM. Meanwhile, we note that one of the options for regulatory reform CEPA proposes is of particular relevance to the battery market:

> **Majority of network services competitive.** The network operator will be unregulated insofar as its offered services are concerned. The structure of the sector may still be regulated (e.g., vertical separation), and price monitoring may be in place, but otherwise the services will be subject to standard competition laws.[24]

1.6 Market changes

The last year has seen an explosion in the number of small (generally under 10 kWh) grid-connected batteries being offered to the residential and small commercial market, starting with Tesla's first Australian installations in late 2015. With retail prices now below the critical price point of $1000/kWh installed, this may be (as an Energeia report calls it) still an "enthusiast's"[25] or early adopter's market, but there is little doubt that it is on the cusp of mass market acceptance – especially for small peak-shaving units where consumers are on time of use or peak demand tariffs,

but also in particular scenarios such as the 135,000 NSW households coming off their 60 cent premium feed-in tariff (FiT) at the end of 2016.[26]

Driven by a range factors including declining production costs, carbon reduction and renewable energy policies and rising electricity prices, projections are uniformly bullish. For instance,

> The International Renewable Energy Agency (IRENA) has estimated the world would need 150 GW of battery storage by 2030 [up from only about 5 GW in 2015] if it is to meet the desired target of 45 per cent of power generated from renewable sources.[27]

Locally, in its 2016 Emerging Technologies Information Paper, AEMO forecast an increase in the installed capacity of battery storage in the residential market alone from 529MWh in 2017 to nearly 8,000MWh in 2034 – a 15-fold increase.[28]

In Australia, interest has boomed in the past year not only in the residential sector but for grid-side batteries as well. Mountain reported in 2015 that "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."[29] A year later, this is probably still the case. Appendix 2 lists some 25 network battery projects, most of them current or soon to commence, on both sides of the meter and including a burgeoning number of an emerging third category: microgrid projects. While most past projects appear to have been trials funded by the DMIA or ARENA, increasingly networks are considering batteries to be an integral part of their forward planning, particularly in relation to the following scenarios:

1. On the consumer side, to reduce peak demand by injecting more local renewable generation into the local grid.
2. On the grid side, to balance the output of renewable generation in remote or fringe of grid locations.
3. On microgrids, to enable the sharing of local PV generation between neighbours, reducing the size of the grid connection required or facilitating a community's desire to reduce its carbon emissions.[30]

However, to date this interest has not translated into batteries being adopted as "business as usual" alternatives to other forms of capex. For example, as part of SA Power Networks' RIT-D process to assess the viability of alternatives to spending $45 million on replacing the undersea cable to Kangaroo Island, the Institute for Sustainable Futures at UTS (with ARENA funding) modelled the cost of four options for meeting up to 100 per cent of the island's electricity demand on the island using a mix of renewables, energy efficiency, demand management, batteries and gensets. It found that batteries would play a role as part of a 100 per cent renewable, cable-free option, but that this would be significantly more expensive than a 90 per cent renewables solution with diesel backup for the other 10 per cent.[31] Also, no analysis to date has been provided to suggest that consumer-side storage is a more economically efficient option to provide network services compared to centralised grid-side storage.

1.7 Policy changes

Changing consumer preferences and increasing affordability aside, the other factor that is likely to lead to a rapid uptake of grid-side batteries in particular is the need better to integrate Australia's climate and energy policies. In the recent past, these two critical arms of public policy have not been well integrated, thanks primarily to the lack of a bipartisan approach to climate policy and the current federal government's lack of support for renewable energy investment.

However, in 2015 the COAG Energy Council (EC) acknowledged the need for better integration, especially in light of Australia's (inadequate) Paris climate change commitments:

> The successful integration of carbon and energy policies will be critical to meeting Australia's emissions reduction target of 26 to 28 per cent below 2005 levels by 2030. Ministers will develop a national approach to connect environmental outcomes and energy policy in the interests of consumers.[32]

The same communique recognised the need for a workplan related to emerging technologies including batteries as critical to this integration process, examining, inter alia, "Those services that require economic regulation and those that should be opened to competition". How the EC plans to effect that integration is discussed in more detail below.

In relation specifically to climate change, Federal Parliament is due shortly to ratify Australia's December 2015 Paris Climate Change Conference commitment to reduce emissions by at least 26 per cent by 2030. In September 2016 the Climate Change Authority published its "policy toolkit" to achieve that goal, including an emissions intensity scheme for the electricity sector. In 2017 there is expected to be a Federal Government review of Australia's climate change policies and legislation.

Whatever the outcome of the 2017 review, there is currently no government plan to date that will allow even this modest 26 per cent target to be met. Assuming some kind of emissions trading or intensity scheme will need to be introduced very soon, the most obvious outcome is higher prices for fossil fuelled electricity, favouring renewable energy generation and thus investment – and by extension, grid-scale energy storage in order to dispatch energy to meet peak demand, to help manage the intermittency of solar and wind farm output, to maintain system security and to manage voltage and frequency fluctuations.

Also of relevance is Australia's recently shrunken Renewable Energy Target, which requires that at least 33,000 GWh of generation capacity must be obtained from renewable energy sources by 2020. The current government's policies have led to a crisis of confidence among renewable energy proponents, leading to a shortfall in the construction of new projects. Assuming this shortfall will be overcome before the 2020 deadline, it is likely that there will be a consequent boom in grid-scale (ie, over 1 MW) battery and other energy storage projects.

1.8 Rule changes

In September 2016 the EC submitted a rule change request to the AEMC to "promote the development of competitive markets for new technologies which are prevalent in the contestable market and capable of providing multiple revenue streams".[33] The request proposes changes to service classification

> to clarify the boundaries of services that can be provided by a DNSP in their regulated capacity and to provide enhanced regulatory certainty around the likely treatment where technologies may provide multiple services i.e. in the regulated and contestable markets[34]

as well as amendments to the AER's service classification process, which it regards as somewhat ad hoc and overly constrained.

The rule change request identifies the risk to competition of network ownership of batteries and, like the AEMC, takes a pro-contestability stance, without wishing to prevent network ownership of storage where competition has not yet developed, or on grid fringes where

> the competitive market cannot deliver the service within a reasonable period of time and regulated service provision is the only means by which customers could access the service and receive benefits.[35]

The EC disagreed, however, with the AEMC's spatial approach to defining the limits of distribution services (i.e., its proposal to make all consumer-side storage services contestable), in view of the overall service (rather than spatial) approach to classifications.

Unfortunately, while identifying issues in need of reform, the EC's rule change request does not go into any detail about how the rules should be changed. Their request is likely to be joined by other

related requests shortly, and we hope that these will provide more direction for the AEMC as it combines these requests into a single process.

1.9 Value streams

The AER summarises the principal market impact of batteries as follows:

> …customer investment in smart appliances and battery storage could shift the amount of power that customers withdraw from or inject into a network throughout the day. These developments have stemmed the historical growth in peak demand, delaying the need for costly network augmentations.[36]

However, the great boon, and the great regulatory complexifier, of batteries is their propensity to deliver multiple value streams. Here is a summary relevant to the Australian context, drawn from several sources.[37]

Table 1: Battery value streams

Value stream	Consumer benefit	Network benefit
Peak demand management 1: Reduced augmentation + replacement costs	✓ Reduced bills from network charges	✓ Lower capex requirements
Peak demand management 2: Less demand for generation from expensive peaking plants	✓ Potentially lower bills for wholesale costs	
Peak demand management 3: Potentially lower time of use and demand tariffs	✓ Reduced bills from network charges	✓ Lower capex requirements
Voltage + frequency control		✓ Ancillary services market
Arbitraging (energy sales)	✓ Sale of excess PV output	✓ Charge low, sell high
Increased control of supply	✓	
Increased utilisation of solar output	✓ Lower carbon emissions	
Backup power	✓ Some products only	✓ Black start
Power system security (management of multiple sources of intermittent generation)		✓ Eg multiple wind farms in same area
Isolated feeders (edge of grid)		✓ Local batteries may obviate need for line repex or augex
Microgrids – selling local energy	✓ $ value; community vibe	✓ Income may decrease but most microgrids maintain a skinny grid connection

2. WHAT DO CONSUMERS WANT?

Pursuant to the National Electricity Objective (NEO), the NEM is intended to operate in the long term interest of consumers (LTIC). This is an appropriate and laudable objective, even if we may argue with the very narrow and prescriptive way it is defined in the National Electricity Law (NEL), there being no reference to social equity or environmental sustainability; and even though the near doubling of retail bills in recent years in the absence of higher demand can hardly be said to have been in consumers' interests. So the objective is a long way from being realised.

In the view of ECA, the LTIC may be interpreted as the ability of consumers to achieve their desired access to energy products and services at least cost and with comparable safety, reliability, etc. In other words, if a consumer decides s/he wants a battery, s/he should be able to procure one at the least possible cost, highest possible standard of safety and reliability, and so on. This seems to us to be a reasonable working definition in view of the current limitations of the NEO.

2.1 Monopoly or competition?

The question then arises; what regulatory arrangements are most likely to be in the LTIC in relation to the emerging battery market? Here we must turn to the separation of monopoly and competitive parts of the supply chain in the National Electricity Rules (NER). Mountain discusses the particular rationale for why transmission networks cannot own generation assets; but this separation also reflects a more fundamental ideology going back to the 1991 Hilmer Competition Review. In a sentiment that has become an article of faith for Australian policy makers and regulators ever since, Hilmer argued that

> Competition offers the promise of lower prices and improved choice for consumers and greater efficiency, higher economic growth and increased employment opportunities for the economy as a whole.[38]

Post-Hilmer, "regulated natural monopoly networks or network service providers were separated out from more competitive generation and retail supply, which were largely unregulated."[39] The AEMC clearly concurs, arguing in its storage report that

> Market arrangements should promote consumer choice while providing a level playing field for market participants. Consumer choice based on clear price signals then drives innovation, with costs minimised by each service provider seeking to provide a compelling value proposition to the consumer. Finally, it is only in instances where competitive forces cannot deliver these consumer benefits that economic regulation should be contemplated.[40]

In short, the NEM operates on the assumption that monopoly transmission and distribution networks are a necessary evil, there being no point having more than one network serving the same consumer; that competition is to be encouraged wherever possible in other parts of the supply chain (generation and retail); and that even in relation to networks, competition for services should be encouraged (witness the recent rule change around competition in metering).

There has been much talk from the Energy Networks Association (ENA) and its consultants in the past year about the need for more deregulation to encourage innovative business models to emerge in the decentralised energy market. For instance, according to CSIRO and the ENA (in relation to the emerging decentralised market),

> In this environment, the need for economic regulation of some network services may diminish. It will be replaced by strong competitive and commercial incentives to provide low cost, non-discriminatory grid access, and to maximise grid use. [41]

We completely agree; but this needs to be a two-way street. This argument tends to be expressed in the form of "Competition = good, regulation = bad", sometimes ignoring the fact that effective regulation can be key to competition. If monopoly businesses want less regulation, they in turn need

to be less monopolistic. For instance, our concern (and the Clean Energy Council's) (CEC's) below about the effectiveness of ring-fencing would be lessened somewhat if the AEMC responded to the CEC's recommendation that connection standards should be in the hands of independent body rather than remaining in the "quasi-regulatory" hands of individual networks, even for batteries not designed to export energy to the grid.

In other words, if networks want to enter the consumer-side battery market, they need to relinquish control over the means by which consumers connect to the grid. This is especially critical given that the results of an AusNet residential battery storage trial found that the financial benefit of these consumer-side installations to the network itself ("in peak demand management [eg,] for identified capacity constraints in the network, where demand is forecast to be greater than the capacity of the network assets")[42] was double that of the benefit to the household.

In any case, evidence of the benefits of competition in the retail domain remains equivocal in view of the market dominance of the "big three" retailers (Origin, AGL and EnergyAustralia) and the evidence of excessive profit margins in some supposedly competitive jurisdictions.[43] There is also mounting evidence of generators gaming that supposedly competitive market, especially this year in South Australia.[44] While these outcomes may point to remaining barriers to effective competition rather than a critique of competition per se, clearly it should not be regarded as a cure-all or a consumer-friendly end in itself.

Conversely, the bill shock caused by $45 billion of investment in poles and wires from 2009-14 despite peak demand and total consumption declining in most parts of the NEM is damning evidence of the risks to consumers of a lack of competition (and perhaps also of government ownership and control of networks, given that the imposition of high deterministic reliability standards in NSW and in Queensland was a prime cause of the gold plating of network assets in those states).

Given this complex and perhaps contradictory background, greater competition cannot on its own be the arbiter of good consumer outcomes in relation to the battery market. Recent polling for ECA found that energy consumers were less satisfied with the value for money of their energy services than for their banking, water, mobile phone, insurance and internet services, and that less than one in two consumers in every jurisdiction but one had a "positive sentiment" about the value for money proposition of their energy services.[45] This is not surprising in view of price increases from 2009-14, and the results are likely to have been even worse had the polling been undertaken after a new round of substantial retail electricity price increases from 1 July 2016 in most jurisdictions started to bite.

While the main cause of the 2016 price increases was higher wholesale prices, earlier increases were primarily due to a combination of high regulated rates of return to networks and the aforementioned leap in capex spending from 2009-14. While rates of return are another matter of serious concern for consumer advocates, consumer- and grid-side batteries both offer the opportunity to reduce future network capex spending, even where there are localised supply constraints.

This opportunity is greater where networks are not able, or do not choose, to add battery investments to their RABs, since doing so effectively shifts the investment risk from networks to consumers. In the case of consumer-side batteries, where consumers themselves buy and control these devices they bear most or all of the investment risk. On the grid side, in our view if regulated monopoly businesses want to play in that market, it is appropriate for them to bear most of the risk.

In summary, we consider that *risk-sharing* is a more appropriate indicator than competition of the long term interest of consumers. We propose this while cognisant of the other related non-economic risk that under-investment in batteries by networks may stifle innovation and investment and the shift to decarbonise the electricity sector. As a starting point, we consider it appropriate for

consumers to bear most of the economic risk of their direct investments in batteries, while networks bear most of the risk from their investments on the grid side of the meter.

2.2 What do consumers really want?

To date we have considered the interests of consumers mainly in terms of the economic outcomes. But this is not the only reason to invest in them, even on the consumer side of the meter. Nationally, we know that about one-third of residential and nearly half of all business consumers say they intend to buy batteries to store electricity, and that these figures rise to over half for consumers who already have solar power.[46] That represents a huge potential market for consumer-side batteries, but there is limited data around *why* consumers are so interested.

Recent polling for The Australia Institute (TAI) found that

- 23% of respondents choose unplugging from the grid as a reason to get batteries.
- 39% of respondents choose independence from their energy company as a reason to get batteries.
- 34% of respondents say they are prepared to invest in storage batteries with a payback period of 5 years or more.[47]

In other words, their motivations appear to be related more to energy independence than to narrow financial considerations. However, the same survey found that three-quarters of respondents cited "Saving money on electricity bills" as the main reason for wanting to install batteries,[48] indicating a high level of confusion or misinformation about the current economics of residential batteries.

In our anecdotal experience as consumer advocates with direct access to various communities of interest, what consumers are likely to want from batteries on their side of the meter can be summarised as follows:

In terms of tangibles, they want access to a technology that can help them to

1. *Reduce energy bills*, usually without compromising reliability of supply.
2. Make better use of their rooftop solar energy and thus *reduce carbon emissions* from their consumption.

But there are less tangible desired outcomes at play, too; as noted above by TAI, some consumers also want to

3. *Increase their control* over their energy supply (the "Stick it to The Man" syndrome).

In relation to grid-side batteries, consumers don't get a direct say, of course, but it is safe to assume that primarily they would want networks to use batteries to keep prices down and maintain reliability of supply. Some would also value their potential to store local or centralised renewable energy, although of course they can store fossil fuelled power as well, and we are yet to see evidence of any networks showing environmental leadership by guaranteeing to only charge grid-side batteries with renewable energy.[4950]

Here, too, there is evidence of another intangible at play (or one that combines all of the above). Some rural communities may seek to use batteries as part of renewable energy systems delivered by microgrids enabling them to achieve zero net energy status (that is, they produce at least as much energy as they consume).[51]

Against all this, though, we need to recognise that what consumers who are currently unable to afford batteries, or whose dwelling type or rental status prevents this, may want is *not* to cross-subsidise those who are able to install them. The absence in most jurisdictions of battery subsidies will go some way to mollifying this concern, as would the introduction of subsidies directed specifically at low income households. On the other hand, though, if and when they are passed through by retailers, the move to more cost-reflective (time of use and demand) network tariffs is likely to favour households and businesses which can afford batteries. That is, batteries will provide

an increasingly cost-effective means of meeting peak demand behind the meter without buying increasingly expensive peak electricity from the grid; and because total network costs and revenue will not change accordingly in the short term, consumers unable to shift their consumption or install batteries will inevitably pay more. This represents an unintended cross-subsidy from lower income households to those able to afford batteries.

Following on from these overarching goals come a number of second-order enablers:

1. Access to a *variety* of products to enable them to choose the best product to meet their needs, including in relation to the trade-off between cost and reliability.
2. *Transparency* of information and explicit informed consent around products and contracts.
3. *Flexibility* around products (eg, via modularity), services and contracts

The question then arises; what regulatory regime can best deliver these outcomes? But before turning our minds to that issue, we should first consider the range of scenarios under which consumers may face risks from poor regulation.

2.3 What could possibly go wrong?

The multiple permutations of location, ownership, control, main purpose and other value streams make it inevitable that things will not always pan out to the benefit of consumers. We design regulatory regimes to reduce the risk of worst case scenarios as much as to provide guidance for optimal outcomes. Here are some of the risks in unfettered network ownership and control of batteries on both sides of the meter:

1. A network that owns consumer-side batteries is perceived to be adopting different standards or timelines or is withholding relevant information in relation to third party installations.
2. A network that owns grid-side batteries arbitrages the energy value during peak periods, feeding the energy into the upstream grid and making it unavailable to meet local peak demand.
3. A network that owns grid-side batteries installs them instead of adequately considering non-network alternatives such as demand management and energy efficiency.
4. A network installs batteries to perform a regulate service such as peak demand management to reduce future capex requirements, and is entitled to add them to its asset base. It later discovers that arbitraging provides a more profitable value stream, and thereby effectively "double dips" on its investment.
5. Network investment on grid-side storage crowds out the consumer-side market, or alternately results in inefficient investment as more storage capacity is installed than required to, say, smooth peak demand.

Here is how the AEMC summarises these risks to consumers:

> The network business may… use its network to advantage its storage assets (over other forms of distributed energy owned by rivals, or over conventional generation) when competing in the wholesale or retail market. It could use the connections process to make it difficult for rivals to install storage behind the meter, if the business or an affiliate were competing in that space. The network business could use information it gains in the course of its regulated activities that is not available to other competitors to provide an advantage to its storage-related activities – for instance, information regarding local network issues and customer demand profiles. The network business could leverage its regulated interactions with customers to also offer non-regulated services, in a manner which results in an advantage for its non-regulated activities and does not make clear to customers that they could choose an alternative supplier for these activities.[52]

Doubtless there are already solutions available to each of these problems; but doubtless too, others unforeseen will also arise. And we note that, conversely, there may be worst case scenarios from an overly restrictive approach to network investment in grid-side batteries – especially the likelihood that this investment may not happen at all in remote or fringe-of-grid locations where it may be unlikely that other companies could provide similar services at a competitive price, given the high cost to supply and the prior existence of network infrastructure in those areas.

The challenge is to establish a framework for battery storage so as to make the most egregious scenarios unlikely to eventuate, and to encourage good behaviour.

2.4 Conclusion

In our view there are therefore three fundamental objectives that should guide consideration of the regulation of batteries consistent with the long term interest of consumers:

1. Minimising risk to consumers of inefficient investment by other parties.
2. Maximising opportunities for competition and consumer choice.
3. Maximising opportunities for the decarbonisation of the Australian electricity sector.

Unlike some other stakeholders, we do not see any inconsistency between objectives relating to economic efficiency, consumer choice and environmental responsibility. These are the principles that will guide the remainder of this paper.

3. CONSUMER SIDE BATTERY REGULATION

Networks want to be able to own and control batteries behind the customer's meter – and indeed, some are already doing it. Mountain recommends that networks "be barred from the ownership of batteries that are located behind the customer's meter",[53] although he also recommends that they be allowed to develop unregulated ring-fenced businesses to supply batteries behind the meter.

There are two main arguments against networks owning consumer-side batteries. One was discussed in considerable detail by the AEMC in its *Integration of storage final report*. Consistent with its belief in the value of competitive markets, the AEMC concluded that storage should be regarded as a contestable market. In order to protect the already fiercely competitive consumer-side battery market, it recommended that "Network businesses should only be allowed to own storage behind the meter through an effectively ring-fenced affiliate". It does, though, go on to note that "There are however a range of options available to them, through commercial arrangements with other service providers, to leverage the benefits of storage."[54] The EC agrees, arguing that

> …where a DNSP wants to invest in storage (and other technologies) 'behind the meter' to provide support for the regulated service, such services should be sourced from the competitive market i.e. from a third party or ring-fenced affiliate.[55]

As consumer advocates, we are yet to see a convincing argument as to why regulated monopoly businesses should be allowed to expand their control into a competitive part of the supply chain, potentially adding consumer-side batteries to their asset bases in the process. We therefore concur with the AEMC and the EC on this point.

The second argument concerns the control that networks exercise in relation to connection standards and timing, and the inevitable information asymmetry that goes with these. The AEMC summarised this problem as:

> The network business is able to restrict competition in a competitive market by restricting access to infrastructure or providing access on less favourable terms than to its affiliate.[56]

This issue is dealt with in more detail in relation to networks' control of connection standards in the CEC's submission to the AEMC storage review. According to the CEC, networks "are likely to utilise their monopoly position to exercise even greater control of approval of connections of solar with storage."[57]

In our view, no compelling evidence has been provided to suggest that the risk of potential abuse of monopoly power is less than the risk of keeping networks out of this market. For both of these reasons, our strong recommendation is that networks should not be able to own consumer-side batteries – except, if necessary, through ring-fenced businesses.

However, we remain sceptical about the benefits of ring-fencing as a work-around that will still enable networks to operate in the consumer-side battery market. This issue was dealt with in the TEC et al group submission to the AER's 2016 *Ring-fencing guideline preliminary position paper*. Suffice it to say that consumer advocates have not been provided with any evidence that the economic or other benefits of ring-fencing outweigh the administrative and compliance costs and potential risks; or that this solution is preferable, from a consumer perspective, to complete structural separation of retail from network businesses.

We recognise that mandating structural separation is beyond the AER's current powers, and would therefore require a rule change. One of our recommendations is therefore that a consumer advocate should consider lodging a rule change request to require the structural separation of retail and network businesses in relation to new products and services in particular.[58]

Meanwhile, we note that there appears to be a lack of clarity around where the distribution system ends (ie, at the customer's meter or potentially behind it),[59] and that the AEMC has accordingly recommended that

> …the COAG Energy Council task the AEMC with reviewing the NER and identifying the necessary amendments to give effect to… clarifying the boundaries of services that can be provided by a DNSP in its capacity as a regulated entity.[60]

Finally, while this paper makes a clear distinction between network ownership of consumer-side and grid-side batteries, this distinction may prove to be somewhat artificial. As noted above, a network could crowd out the consumer-side battery market in some locations without even entering it, by offering similar services from its own grid-side unit at prices the residential market cannot compete with.

This raises the related risk of overinvestment in storage via duplication on the consumer and grid sides. Imagine a low voltage network that is faced with a peak load problem. The network cost effectively invests in grid-side storage rather than new network investment to meet its reliability requirements. Customers benefit from the lower costs involved in providing the network service. Let's assume that those same customers on the street are faced with a time of use (TOU) tariff (as on other streets). There is no benefit from customer-side storage, because the network has already invested in the capacity needed. However, those same customers respond to the TOU tariff incentive and invest in storage. This effectively makes the grid-storage redundant. But the network will still be able to recover the costs of the grid-storage. Similarly, the customer can finance its storage investment via the TOU tariff bill savings. How is this in the long term interest of consumers?

To avoid this problem, either demand tariffs should be locational, or the RIT and related planning and investment regulations should ensure that grid-side batteries should only be installed on constrained parts of the network.

Scenario 1 – Consumer-side peak demand management

A holiday area experiences peak demand for short periods only over the summer vacations, especially during heatwaves. Instead of continuing to augment the grid to cater for these events, the network wants to install peak-shaving batteries in holiday homes at lower cost.

Assuming that individual household batteries are a more economically efficient solution than one (or more) larger, centralised grid-side battery, this scenario is potentially a win-win for consumers and networks – also assuming that the capital and running costs of the batteries are subsidised by the network.

It does, however, appear to be a legitimate scenario for the involvement of ring-fenced businesses or third parties to ensure the lowest cost installation and to manage the multiple value streams involved. If ring-fencing is effective, this should also reduce the risk that the network will use its monopoly position to restrict the reach of competitors in supplying batteries direct to consumers.

It also raises issues around the extent to which networks could or should control the charging and discharging of consumer-side batteries. If the network has subsidised the battery to ensure that peak demand is met behind the meter through battery discharges, should it also be entitled to require households and businesses to divert their solar energy to charge the batteries during the day (rather than consuming the solar energy onsite); (if there is no solar installed) to buy grid electricity at a time of the network's choosing to ensure the battery is fully charged in readiness for critical peak events; or even to export electricity from their battery during critical peaks if they are not using the energy behind the meter?

These questions arise separate to issues of prior informed consent and other consumer protections for consumer-side batteries. But in our view the direct involvement of networks in this market is likely to be more problematic than that of ring-fenced entities or third parties.

Scenario 2 – Going offgrid

The electricity supply to a bushy rural area needs to meet new bushfire regulations. The network has two options: install expensive new poles and wires; or the cheaper option of solar, batteries and backup diesel generators on individual properties.

This scenario raises a number of complex issues, many of which go beyond the scope of this paper, such as the voluntary or forced nature of the disconnection process, whether (and for how long) disconnected households could or should still be network customers, and who owns and pays for the consumer-side kit.

These important issues aside, of more direct relevance is the fact that (assuming the capital cost is under $5 million) the RIT-D would not require the network to go to market (for solar, batteries and generators), so it could preference the traditional poles and wires solution if it is not allowed to own batteries or if ring-fencing is considered too onerous. Even if ring-fencing requirements are not onerous, if the network is required to procure the new consumer-side kit through a ring-fenced entity or a third party as a non-distribution unregulated service, how long would the contract with consumers be for, and what happens when it ends?

In response, we note that one of our recommendations is that to capture many battery projects, the "materiality threshold" for RIT-Ds should be lowered from $5 million to $1 million or less. This should ensure more competition and transparency around scenarios such as this one.

Should the (mini-) RIT-D result in the offgrid solution being preferred, our option for consumer-side batteries would require the kit to be procured from ring-fenced entities or third parties. The conditions under which this would happen – e.g., whether consumers would be entitled to the same level of service as grid-connected customers – would need to be clarified, preferably on a whole of NEM basis.

Finally, another of our recommendations is for an exemptions framework where networks can argue that the absence (preferably after going to market) of effective competition in scenarios such as this means that the best consumer outcome may be for network ownership and control of behind the meter batteries and related services.

4. GRID SIDE BATTERY REGULATION

The main purpose of this section is to whittle Mountain's seven options for the regulation of network ownership of grid-side batteries down to a single preference. For better or worse, this has been done primarily by filtering these options through the *realpolitik* lens of what is possible through the current regulatory framework with limited reforms such as individual rule changes, rather than requiring wholesale changes to the structure of the NER or legislative changes to the NEL (as much as these may be called for or required in due course); and in light of recent and mooted reforms from the EC, AEMC and AER.

It assumes, for instance, that the AEMC is unlikely to countenance an option involving an arbitrary limit on the percentage of grid-side battery capacity allowed to be owned by any network and added to its asset base. It also acknowledges that under the current NER, the AER can only regulate services, rather than assets.[61] Restricting the assets such as batteries that networks can own would require another rule change; one we consider the AEMC is currently unlikely to view favourably in view of its strong preference for technology-neutral regulation.

4.1 Option 1 (Mountain's Option 2): NSPs may include batteries in the RAB

Under this option, networks may own batteries, but "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."[62] The whole network investment in batteries may be added to RABs.

The main advantage of this option is that it allows networks to develop batteries to provide the services that they are good at (eg, managing peak demand), while not restricting them from profiting from other value streams such as arbitraging. It is also relatively simple, since the complications required by ring-fencing non-network services and periodically revisiting the breakdown of value streams are avoided. It does not prevent other parties from investing in grid-side batteries where the services they provide (especially arbitraging, but also managing the internal energy flows in microgrids) do not affect regulated network services.

The main disadvantage of this approach is that there is nothing to incentivise networks to allow other parties into this space. It also allows them to put the whole battery investment into their RABs, even though some value streams may be for unregulated or contestable services. Finally, by giving the green light to capex investments it does nothing to promote non-network alternatives such as demand management and energy efficiency.

4.2 Option 2 (Mountain's Option 4): Part of battery that provides network benefits included in RAB

As Mountain explains, "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."[63] Unregulated or contestable services such as arbitraging would have to be obtained and managed through the open market, involving third parties or ring-fenced entities.

The main advantage of this option (which might be abbreviated to *Part RAB, part opex*) is that it allows networks to capitalise on the portion of their investment that is intended to provide regulated network services, while also encouraging them

> 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 cannot 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.[64]

It also ensures that consumers do not bear the risk for that portion of the investment that is not for a regulated network service.

The main disadvantages of this option are that it requires complex ongoing calculations of the value of regulated network versus contestable market services, and that there may therefore be significant advantages to networks partnering with their own ring-fenced entities rather than third parties to procure the latter services. It also requires that the incentives for procuring regulated network services via capex and opex are similarly attractive, so that networks are not tempted to procure these services solely as capex and add them to asset bases accordingly.

Mountain also raises the option (4a) of networks having a ceiling of the capital value of batteries (say 50 per cent) being allowed to be added to RABs, provided that ceiling also represents no more than the value of regulated network services involved. We consider this sub-option has merit, but in our experience consider that it is likely to result in every battery project being added to RABs to the tune of *exactly* 50 per cent, limiting the potential value of unregulated services also to 50 per cent. And where grid-side battery projects are intended largely or exclusively for regulated network services, it may effectively disincentvise the investment.

Finally, we do not consider that this option precludes Mountain's Option 5: "NSPs restricted to technology-agnostic procurement", since the decision to choose a project that involves adding part of the value to the RAB is required under the NER to be made after undergoing a regulatory investment test (RIT) – at least where the value is over $5 million, and (assuming the current AER rule change request is adopted by the AEMC) including replacement capex (repex) as well as augmentation capex (augex). However, most battery projects are worth well under $5 million, so this raises the need for a RIT-type process for smaller capex projects as well. This will be discussed below.

4.3 Option 3 (Mountain's Option 6): NSPs prohibited from including batteries in their RABs

The *No RAB, all opex* option has the advantages of simplicity and clarity. By requiring that all battery services be procured from third parties, the energy storage market gets a clear message that its products and services will be required to roll out grid-side batteries. As Mountain says,

> [T]his approach… 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.[65]

This is also close to ECA's November 2015 policy position on battery regulation, in which it argues that rate of return regulated firms have an incentive

> … to inefficiently prefer capital expenditure over operating expenditure. Restricting DNSPs to the ability to buy network support and reliability "as a service" is the most effective way to mitigate risk.
>
> Additionally, restricting DNSPs to engaging in storage only as an acquirer of a service provides the DNSPs with the incentive to develop the processes and services needed to most effectively integrate both embedded storage and behind the meter storage.[66]

On the other hand, this option carries the risk that investing in, or procuring services from, batteries will become so unattractive to networks that they simply will not bother, and will revert to network augmentation projects to meet peak demand constraints. While this risk is manageable on the consumer side, on the grid side the monopoly position of networks requires that we take into consideration the fact that it is not a level playing field for new entrants, and that the power of monopoly and incumbency be recognised.

Mountain writes that "It would be helpful to understand why NSPs might refuse or be reluctant to procure battery services from others." In our experience, this can be put down to a combination of corporate culture, a regulatory regime that has traditionally been weighted in favour of capex over

opex investment, and a belief that networks have unmatched knowledge of and experience in managing their grid and that other parties would be playing catch-up. In our view this belief has more merit in relation to some regulated network services than to other currently regulated and contestable services, in particular arbitraging.

The place where this option may be problematic is in relation to fringe-of-grid or remote area power systems (RAPS). Networks argue that in remote areas, the idea that there already exists a competitive market for battery services network, allowing them to access these services as opex instead of capex at reasonable cost, is unrealistic. For instance, they are likely to be the only party with assets in the locality which are already being paid for under the RAB, and which can therefore be utilised at relatively low cost. The cost to install and run batteries in such locations would, the argument runs, be significantly higher for any new player, while there would be practical difficulties with using a ring-fenced business (eg, since local staff may be limited). If networks are prevented from installing batteries as regulated services using capex in such situations, they may choose to go for traditional network solutions instead.

In our view this argument is of theoretical relevance but is untested, and as discussed below, is itself problematic.

5.4 Discussion

On our view, Option 3 is likely to produce the best outcomes for consumers, because it is most likely to meet our three central principles for the LTIC: that is, it

1. Encourages the development of a competitive market for grid-side battery services.
2. Minimises the economic risk to consumers of potential inefficient investment.
3. Therefore helps, or at least does not hinder, the rollout of energy storage to support the decarbonisation of the electricity sector.

However, there are three critical caveats involved in this preference that need to be addressed:

1. As discussed above, in relation to fringe-of-grid and RAPS it may result in underinvestment by networks unable to leverage their existing investments in these locations, which may be uneconomic to service through the competitive market.
2. It assumes that other incentives, especially to balance investment in capex versus opex, are working well.
3. It may require a rule change to require battery services to be separately defined and classified as contestable.

These caveats are now briefly discussed in turn.

1. This appears to be the AEMC's current position, and is shared by the EC, which finds that

   > …there should not be a blanket prohibition on DNSPs investment in storage or other new technologies emerging in the contestable market.
   >
   > Energy Council recognises there may be circumstances where competition takes time to develop, and that investment by networks in new technologies 'on the network' will support a more efficient investment and higher quality regulated network services.[67]

   However, the EC does not provide any evidence to support its concern or proposition. Given the cooperation by networks with third parties in current storage trials, most of which involve capturing multiple value streams, it is not clear why adding storage assets to RABs will "support a more efficient investment and higher quality regulated network services". In our view networks have to date not mounted a compelling case in respect of the economic, competition or decarbonisation benefits of them controlling this emerging market on the grid side. Were such a case able to be made, we would prefer to see an exemptions

framework in place for a limited time until effective competition has developed. Conversely, there is a significant regulatory and economic risk in developing a regulatory framework that assume the absence of, or structural flaws in, the competitive market that regulation is intended to foster, since (in this case) once allowed, network ownership of grid-side batteries could go on to stymie the growth of a competitive market.

So when the EC argues that

> …there are likely to be some instances potentially in geographically isolated segments of the network where such investments 'behind the meter' by a DNSP might reasonably be part of the regulated service; that is in cases where it can be established that the competitive market cannot deliver the service within a reasonable period of time and regulated service provision is the only means by which customers could access the service and receive benefits. It is however expected that these circumstances would be the exception to the general rule…[68]

our response is that the rules should make appropriate exemptions for the exceptions rather than build the regulatory regime around them.

2. A number of reforms have been introduced in recent years (such as the capital expenditure sharing scheme [CESS] and efficiency benefit sharing scheme [EBSS]) that are intended to balance capex and opex, while the demand management incentive scheme (DMIS) still awaits preparation by the AER (and even then, the AER is not required under the rules to apply it to any particular network revenue determination). We have been assured by some networks that they would favour the procurement of battery services by opex because it obviates the need for a lumpy capital outlay; but this preference is not yet evident in most announced projects (which are admittedly mostly trials). And while the last round of revenue determinations provided evidence of a shift by most networks from capex to opex spending, this may be simply a reflection of a lower growth environment rather than a shift in preference for how regulated network services are procured.

   In other words, this is a legitimate concern. However, in our view it should not be a determining factor in respect of the regulation of new products and services. Put simply, if there is still a bias towards capex in either the rules or network behaviour, this should be separately addressed. A historical regulatory flaw should not determine the regulation of a new industry.

3. The rationale behind this rule change is discussed in detail in Appendix 3. Basically, this caveat could require the AEMC to abandon its traditional technology-neutral stance, and the AER to regulate assets rather than the services. An alternative solution is discussed below.

5.5 Conclusion

Bearing in mind the caveats considered above, we therefore consider that the *No RAB, all opex* option should be supported as the one most likely to meet our three objectives of minimising risks to consumers, increasing consumer choice and competition, and aiding the decarbonisation of the electricity sector. That is, grid-side energy storage services should be procured by networks through the competitive market as opex rather than capex.

We see no evidence to date that this approach will dampen the uptake of grid-side storage, even in fringe of grid locations (see Scenario 2 above). There may, though, need to be an *exemptions framework* in place – preferably for a limited period only – to cater for situations in which a competitive market for battery services is unlikely to exist.

We are aware that the *No RAB, all opex* option may require regulatory reforms. Here are two possible solutions: one minimalist in terms of the process, but likely to have profound consequences for the balance of regulated and unregulated services provided by networks and others; the other

equally profound in terms of the (potentially complex and far-reaching) move from the regulation of services to the regulation of assets.

Under **Implementation solution 3.1,** *energy storage services* would be separately defined (akin to metering and connection services) in the rules, and then required to be unregulated in the F&A process. To implement this option, a rule change will probably be required to separately define energy storage services (eg, via section 6.2.1 – Classification of distribution services, of the NER). The AER would then, through the F&A process, classify the services provided by energy storage as *unregulated* and therefore contestable. The main issues we foresee with this solution 3 are that

- It is debateable whether the services provided by batteries are actually unique (see 6.2 below).
- It would require the AER to classify assets rather than services (see Appendix 3).

Alternately, under **Implementation solution 3.2**, *all* services currently classified as Distribution – Network but potentially provided by batteries (identified in Appendix 3 as relating to *managing peak demand, supporting isolated feeders* and *providing power system security*) should instead be classified as Distribution - Unregulated and therefore contestable – that is, whether they are procured via batteries or via traditional network augmentation. This would be part of a move to opening up previously monopoly network services to more competition. Naturally, it would also require close consideration of the interaction of network businesses with third parties or ring-fenced businesses operating more extensively on the grid, to ensure that reliability, safety, etc., are not compromised by the potential fragmenting of responsibilities.

Whichever implementation option is chosen, the classification of battery services as Distribution - Unregulated will obviate the need for another rule change to allow the AER to require them to be procured as opex rather than capex, since unregulated services can only be opex.[69] On the other hand, classifying battery services as unregulated may raise issues relating to how networks can recover the expenditure through their revenue caps, since unregulated distribution services cannot currently be treated as opex and recovered through the revenue cap.

We look forward to working with the AEMC, AER and other stakeholders to clarify and implement the best options for regulatory reform consistent with our objectives.

Scenario 3 – Grid-side peak demand management

A substation is reaching its capacity during occasional summer or winter afternoon and evening peaks.

The network has several options including augmenting the substation capacity; installing a battery (which would be charged during the day from downstream rooftop solar or upstream centralised generation, then discharged during critical peak events); incentivising demand management through peak demand tariffs or energy efficiency rebates; or buying demand response through the wholesale market.

The network decides to test the market for either a substation upgrade or non-network options. It internally costs the former option, and publishes a request for proposals which could include local generation, demand management and response, and batteries.

Under Option 2, if the project is under $5 million there is currently no regulatory requirement for the network to go to tender; it could simply decide that this is a standard control service ("network investment") that it is best placed to provide internally and add to its RAB. Even if it does go to a request for proposals, the network may make it uneconomic for third parties by specifying a limited timeframe for the provision of network support (eg, X MW of summer peak demand for Y years).

If this hurdle can be overcome, the third party provider may be limited to providing one particular service requested by the network, whereas the network itself can take advantage of multiple value streams, bringing in its ring-fenced affiliate to take care of unregulated services such as arbitraging. Even if there is no favouritism, for multiple value streams the network must invoke the cost allocation methodology and/or shared asset guidelines to account for these. The third party is at a significant disadvantage relative to the network itself – and if ring-fencing is less than perfect, relative to its ring-fenced affiliates as well.

Under our preferred Option 3, on the other hand, the value streams provided by grid-side batteries to networks would all be required to be provided as opex by third parties or ring-fenced businesses, whether they are providing regulated or unregulated services. The same company that provides the batteries to manage peak demand could also provide frequency and voltage control services and arbitrage the energy flows: all costs recovered by the network as opex, procured under contract through open tenders. Assuming ring-fencing is effective, the battery provider can compete equally with the network's ring-fenced business. This option is likely to create more certainty, less confusion, lower administrative costs, more infrastructure flexibility, fewer real or perceived barriers to competition, and less risk to consumers from large infrastructure investments being added to RABs.

Scenario 4 – Fringe of grid feeders

A long skinny rural line is reaching capacity due to increased local demand, or is old and needs replacing to maintain reliability.

There are at least two potential situations in which grid-side energy storage may be valuable to networks and local consumers on grid fringes or RAPS: as alternatives to (a) other augex to respond to increasing localised peak demand or (b) repex to maintain reliability on fringes of grid.

Networks argue that in these situations, given their existing presence in the area with infrastructure and staff, the often uneconomic nature of energy supply to these consumers (that is, under postage stamp pricing they are effectively cross-subsidised by other consumers) and the undeveloped nature of the energy storage market, only networks will be able to offer these services from storage devices economically.

This argument has some merit in principle, but since no network has gone to market to provide storage services in grid fringe situations, there is no real-world evidence to substantiate it. We assume that the alternative solution (more poles and wires) would also be expensive. If our *No RAB, all opex* option is implemented, on the other hand, this should create an incentive for third parties to tender for the storage services, procured via opex. If ring-fencing is effective and costs are properly allocated, the related business should have no financial advantage over third party providers. And if networks subsidise a network capex solution, we see no reason why they would not also subsidise the storage/opex solution where it is more economic.

Our preferred option also greatly simplifies the accounting and cost allocation for multiple value streams from batteries, especially arbitraging (when the network charges the battery when demand and presumably the wholesale price of electricity are low, and discharges it when demand and the price are higher).

5. RELATED REFORMS

5.1 The planning process

In response to concerns that the planning process for new network infrastructure may be inadequate to deal with the emerging grid-side battery market – especially in regard to lead times, transparency of information and the $5 million "materiality threshold' for RITs – the AEMC agreed to

> …review the lead times in the planning process to test whether they are appropriate in the face of changing technologies and more distributed energy resources. The review should also consider whether thresholds in the planning process (eg, for the RIT-T and RIT-D) remain appropriate in the face of changing technologies and more distributed energy resources, and whether any other information resources are necessary.[70]

The fruits of this review are not yet in the public domain. However, subsequently the AER has submitted a *Replacement expenditure planning arrangements* rule change request to expand augex planning processes to include repex as well. The AER proposes to change Chapter 5 of the NER to

- Introduce new reporting requirements in both transmission and distribution APRs to require network businesses to provide information on asset retirement decisions and the development of credible options to address network limitations arising from a decision to retire a network asset.
- Introduce a new guideline on replacement capital expenditure which will determine the types of replacement assets captured in the APRs.
- Extend the application of the RIT-T and RIT-D to replacement expenditure.[71]

While these are laudable reforms in isolation, the AER rule change could readily be expanded to include consideration of planning reforms that would benefit the grid-side battery market. For instance, the AER's proposal does not include a change to the materiality threshold. In our view this is critical, since most battery projects, whether individual or aggregated, are worth far less than $5 million. Thus, networks so inclined could procure new kit (and add it to their RABs) without adequately considering batteries (or non-network alternatives) as long as the cost is under $5 million. Conversely, many projects over this threshold may not be amenable to a cheaper battery solution.

It is therefore important that either the threshold for the RITs be substantially reduced – say, to $1 million (which would still exclude many smaller grid-side batteries such as Ergon's 100 kWh GUSS units, unless they are aggregated) – or the rule change should consider alternative means for batteries to be included in the planning process. There could, for instance, be a "mini-RIT" process for projects with a total value of more than $1 million (whether or not it is battery-specific) that sits somewhere between the APR and the current RITs.

As an early part of the rule change and planning process review, the AEMC should also review how effective the RITs have been to date in leading either to networks choosing non-network options or to decisions not to proceed at all, and whether there is a need for greater transparency and regulatory oversight of RITs. We are sceptical that they have been little more than a "tick the boxes" exercise undertaken long after investment decisions have been made by networks, and see little evidence that they have led networks either to choose non-network options or to defer or abandon augex projects.

5.2 Capex and opex incentives

An effective competitive market for grid-side battery services can only emerge if networks are not overly incentivised to install them as capex (and add them to their RABs) rather than purchasing

them on contract from other parties as opex. The AEMC recognised this, recommending that the AER review

- The strength of the EBSS and CESS.
- Whether expenditure on storage services through opex would qualify for the EBSS.
- Whether further incentives are needed on network businesses to consider opportunities to substitute opex for capex, noting the ineligibility of TNSPs for the DMIA and DMIS.[72]

We concur, but note that it is extremely difficult for consumer advocates to assess the relative strength of capex and opex incentives without much more transparency around their operation. Further, the rules give the AER discretion around whether to apply the CESS and EBSS to particular revenue determinations.

We are also concerned that this review might ignore the potential role of demand management (as opex) in "levelling the playing field" vis-à-vis capex. The reformed DMIS – the draft specifications for which were part of the AEMC's 2012 Power of Choice final report – has still not been designed by the AER; and even when it has been, the AER (which argued during the Rule change process against being required even to design such a scheme) has discretion as to whether or not to apply it to any particular revenue determination. While not as cheap as load shifting or curtailment or direct load control, batteries are an effective means of moderating peak demand, and it is important that their potential role be recognised in the DMIS as well as in the above AER and AEMC reviews. In short, we consider it unlikely that capex and opex will be equally attractive to networks without an effective DMIS.

6.3 Ring-fencing

As the AER explains,

> Ring-fencing refers to the separation of regulated services from contestable business activities within a network service provider (NSP). In simple terms, ring-fencing is designed to limit the ability of a regulated service provider to confer an unfair advantage when it or one of its affiliates operates in a contestable market. As noted by the AEMC, the following types of behaviours by NSPs result in harm that ring-fencing aims to avoid:
>
> - cross-subsidising the affiliate's services in the contestable market with revenue derived from its regulated services
> - discrimination in favour of an affiliate operating in a contestable market
> - providing the affiliate with access to commercially sensitive information acquired through the provision of regulated services
> - restricting the access other participants in the contestable market have to the infrastructure services provided by the regulated entity, or providing access on less favourable terms than its affiliate.[73]

These present significant risks not only to competitors in the market, but also to consumers, since any failure of the ring-fencing regime is likely to lead to market dominance by network monopoly businesses, which usually leads in turn via revenue determinations to higher bills. In the absence of any evidence from either the AEMC or AER of either the effectiveness of existing jurisdictional guidelines or from other industries so regulated, consumer advocates see nothing to substantiate the view that ring-fencing is likely to be effective in ensuring that networks with ring-fenced retail businesses can deliver contestable services on either side of the meter in a competitively neutral manner.

The CEC concurs, arguing that

> DNSPs enjoy a uniquely powerful position as monopoly businesses that enjoy the benefits of extreme information asymmetry and quasi-regulatory powers over their competition in connection processes

> and approvals. These conditions mean that a DNSP would be able to exert influence over connection processes with preference to a ring-fenced entity even if this entity were legally separated.[74]

Thus our preference for a stronger regime of full structural separation of network and retail businesses. However, since the AER is unable to impose this without yet another rule change, we reluctantly concur with the factors the AEMC recommends that the AER consider when constructing its NEM-wide ring-fencing guideline this year – with one addition. The guideline should also contain strong measures around monitoring, transparency and compliance, so consumers can have confidence that the guideline is being strongly enforced.

In relation to the content of the AER's *Draft ring-fencing guideline*, in line with our adoption of the *No RAB, all opex* option in relation to grid-side battery regulation, the AER's approach, which is to link the decision as to which services to ring-fence with the service classification decision made as part of each network's F&A process (see Appendix 3), becomes somewhat irrelevant. That is, both of our implementation solutions require different approaches. Under both solutions, all battery services become contestable and can only be procured by networks from ring-fenced businesses or third parties.

We maintain a sceptical approach to the regime for granting exemptions from the guideline. The AER has already granted exemptions to the two Queensland networks for grid-side battery projects, and question whether other networks should also have applied for exemptions in view of the mixed value streams involved. Either way, we hope that a situation does not develop similar to the AER's exempt retail guideline, which has seen literally thousands of exemptions now granted under a variety of categories.

The situation is particularly problematic in relation to arbitraging. Every flow of energy beyond the consumer's meter must be bought and sold by one party or another and settled with AEMO. The amount may be minute in relation to an individual battery, but as ECA pointed out in its submission to Ergon's application for a waiver, at what threshold does the amount become material? From a consumer perspective it is important to see how much money is trading hands through battery arbitraging, and we would welcome the introduction of a mechanism to provide this transparency.

Another conundrum in relation to ring-fencing will be how to deal with changes over time to the relative value of the different value streams produced by batteries. This is a strong argument for a regime of full contestability for all battery services, since the risk does not arise of the value of regulated services (added to RABs and therefore paid for by consumers) diminishing while the value of unregulated services like arbitraging increasing over time. In the absence of full contestability, this reinforces the need for a high level of transparency and periodic review (preferably annually) of the performance of grid-side batteries relative to the network's division of the spoils between regulated and ring-fenced value streams. In theory the AER's shared assets guideline deals with such situations, but its application adds a layer of complexity and compliance costs that are not required under the *No RAB, all opex* option.

6.4 Stand-alone energy systems (SAPS)

There are situations under which energy storage may make it economically viable for some communities to go off-grid rather than the network spending augex or repex to keep them connected to the grid. These scenarios raise a number of legal and regulatory but also broader public policy and equity issues (e.g., who decides when to go offgrid? Who is responsible for centralised off-grid systems? What reliability standards and consumer protections should apply? What happens when the battery warranty runs out?) which go beyond the scope of this paper. Some of them are addressed in the COAG EC's Stand-alone energy systems consultation paper published in September 2016.

6. THE FUTURE

6.1 Imminent review and reform processes

This draft position paper has been prepared with a view to providing a position on consumer-side and grid-side battery regulation that small consumer advocates could take into the following known review and reform processes:

- AER *Ring-fencing guideline*.
- AER-initiated rule change request on *Replacement expenditure planning arrangements*.[75]
- COAG EC rule change request to promote the contestable provision of services from emerging technologies.
- AEMC review of capex-opex incentives.
- ENA/CSIRO Network Transformation Roadmap.
- AEMC-recommended Rule change request regarding the definition of generation.[76]
- CAOG EC Consultation on regulatory implications of stand-alone energy systems in the electricity market.

But there is much, much more to come. In particular, we see an urgent need to review and regulate the *control* of batteries – especially on the consumer side – separate to the issue of their *ownership*.

6.2 The definitional issue

Mountain's suggestion that the complete separation of network ownership from control of batteries and other new technologies is one that we decided falls outside the scope of this paper, but this is not to suggest that it should not be taken seriously. Another idea in this category is the potential need for energy storage to be treated as a distinct part of the supply chain requiring specific rules, rather than it being shoehorned into the category of a generation unit because it acts like a generator when discharging.

The defining function of energy storage is, obviously, the storage rather than the "generation" function, which is performed elsewhere – by rooftop PV, wind farms, etc.[77] The AEMC appears to regard batteries as a form of technology, which therefore should not be separately defined; an alternative view might be that batteries are a (mostly) new element of the supply chain performing a number of services that require unique regulation.

The definitional issue is of more than theoretical relevance. As Mountain points out, transmission networks in the NEM were prevented from owning generators because

> [T]he separation of the monopoly network service activity from the contestable production activity… 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.[78]

If batteries are generating units, then logically distribution networks should be prevented from owning or controlling them because this would represent an intrusion of monopoly market power into a competitive part of the supply chain. The fact is, though, that batteries are much more than generation units, which is why networks have a legitimate interest in owning and/or controlling them (on the grid side at least).

We are not alone in this view. According to legal academic Penelope Crossley,

> …it is critical that legislators and policy makers seek to define energy storage not by the individual functions that it provides but rather as a separate product that is subject to its own set of market rules and regulations.[79]

The definitional issue is, according to Crossley, central to this task. She notes that the 2010 Skinner Bill in California defined energy storage as "commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy".[80]

On the other hand, in terms of the current rules, and the service classification regime in particular, it appears that there is little about energy storage that is unique. From this perspective, the storage of energy is in itself almost irrelevant; what is important is that it allows the battery owner or controller to discharge into the grid or the consumer's supply at the time, in the location and at a price that is economically efficient, increases their choice or assists decarbonisation. Temporary energy storage is, in other words, a different means to achieve similar ends to those covered by the existing regime.

This issue will take some time to clarify. To us it appears for now to turn on whether services or assets are the subject of regulation. If and when the latter is the case, batteries will obviously need to be separately defined.

7.2 Looking further ahead

> While we will remain pragmatic in our approach, we also emphasize that neither regulators nor industry participants should rest on an assumption that regulation and business models always need to adapt slowly and modestly to consumer demands and technology innovation… [T]he need to develop a demand-responsive, climate-friendly, information-centred electric system does not afford us with the luxury of time. With billions of dollars of infrastructure investment impending, as well as carbon reduction requirements and rapid improvements in customer-side technology, the historic pace of regulatory change is inadequate.[81]

Energy storage is an integral part of an emerging decentralised energy system which is likely in time to require a more thorough rewriting of the NER, the current structure of which reflects a linear supply chain moving energy in one direction from centralised generators to passive consumers. We suspect that such a wholesale reform of the regulatory framework will be required once the EC implements its recent statements in meeting communiques about integrating climate and energy policies and regulation. While it goes beyond the scope of this paper to explicitly recommend this, reformulating the NEO or finding another way to require that decision-makers take national decarbonisation targets into account alongside price, reliability, safety, etc., when assessing the LTIC would be an obvious place to begin.

The quote above is from an order related to New York's ground-breaking REV program. Australia could take a lead from this ambitious reform process, which amongst other things involves moving from a model of network revenue based on the value of sunk assets to the network as a platform for the purchase and sale of energy services and thus a fee-for-service model.[82] It also explicitly requires regulatory decisions to factor in the state's renewable energy and low carbon goals.

A particular challenge for Australian networks and regulators is that around half of retail bills goes to paying network charges, whether the energy consumed comes from the rooftop next door or from a megawatt-scale power station hundreds of kilometres away. The advent of affordable energy storage gives individual households and businesses a power of choice far beyond that afforded by solar power alone, making the death spiral an increasingly real possibility – whether by network under-utilisation or by disconnection – unless the problem of massive sunk network assets leading to high network tariffs is addressed. The big losers here, apart from networks themselves, would be legacy consumers – renters and low income households without solar and batteries – who will still need to foot the bill for sunk assets and regulatory inertia.

This problem is much bigger than the regulation of batteries alone, of course. Our challenge here is merely to ensure that this market develops in a way that does not mirror past regulatory failures in

relation to network revenues; to ensure, in other words, that networks are neither incentivised to go on another spending spree, nor are shut out of the market entirely. In our view our proposed option for grid-side battery regulation allows this to occur in the LTIC and specifically while meeting our three objectives of minimising risks to consumers, increasing consumer choice and competition, and aiding the decarbonisation of the electricity sector.

7. RECOMMENDATIONS

Core recommendations

1. Networks should not be able to own or control **consumer-side** batteries except through ring-fenced businesses.
2. **Grid-side** energy storage services should wherever possible be classified as unregulated and thereby procured through opex rather than capex (the *No RAB, all opex* solution).

Subsidiary recommendations

3. Two potential **solutions** should be considered **to implement** our recommended grid-side *No RAB, all opex* solution:
   - 3.1. In future F&A processes, the AER should classify the following services as *Distribution – Network services – Unclassified* (contestable), whether they are provided by batteries or traditional network solutions: responding to increased peak demand, providing backup for isolated feeders and maintaining power system security.
   - 3.2. A proponent should lodge a rule change request to require *battery services* to be separately defined.
4. The AEMC should consider creating a strict **exemptions framework** – preferably for a limited period – to cater for situations in which a competitive market for battery services is unlikely to exist.
5. The AER **repex rule change request** and AEMC **review of planning processes** should both consider
   - 5.1. How the emerging grid-side battery market could benefit from related reforms; e.g., by reducing the materiality threshold from $5 million to $1 million or less, perhaps under a more streamlined process.
   - 5.2. How effective the RITs have been to date in leading either to networks choosing non-network options or to decisions not to proceed at all, and whether there is a need for greater transparency and regulatory oversight of RITs.
6. The AER's forthcoming **DMIS** should explicitly consider the role of batteries in demand management.
7. A rule change should be proposed to allow the AER to impose the full **structural separation** of network and retail businesses.
8. The AER's **Ring-fencing guideline** should be strong enough to prevent networks from favouring ring-fenced businesses over third parties; to this end it should
   - 8.1. Be based on a solid evidence base for the real-world costs and benefits of ring-fencing.
   - 8.2. Contain strong measures around monitoring, transparency and compliance, so consumers can have confidence that the guideline is being strongly enforced.
9. The AEMC should review the AER's **service classification regime** with a view to greatly simplifying and modernising it.
10. C**onnection standards** for solar and batteries should be removed from the discretion of individual networks and placed in the hands of an independent body.

APPENDIX 1

OTHER JURISDICTIONS

Mountain (2015) discussed the regulatory regime for networks and batteries in three other jurisdictions: California, New York and the UK. UK and NY regulators have reiterated their concerns about networks owning batteries. There do not appear to have been any significant developments in California over the past year. In New Zealand, meanwhile, the Commerce Commission appears to be taking a different line to other regulators in allowing networks to own consumer-side batteries.

UK

In 2016 Ofgem reportedly reaffirmed its decision not to allow networks to own energy storage, which it classifies as a generation asset. According to a spokesperson:

> Our principle is network companies shouldn't own or operate storage. We recognise there might be some exceptions to that based on particular circumstances, or particular needs, or where you define storage as something where you just can't develop a competitive market. But I think if you want competitive markets to develop, you need to keep regulated monopolies out of them.[83]

On the other hand, in March 2016 the new National Infrastructure Commission published a report on investment in energy infrastructure. At Budget 2016, the Chancellor confirmed that the government accepted the commission's recommendations in the 'Smart Power' report. Recommendation 2 was as follows:

> The UK should become a world leader in electricity storage systems. Two steps are required:
>
> 1. DECC and Ofgem should review the regulatory and legal status of storage and remove outdated barriers to enable storage to compete fairly with generation across the various interlinked electricity markets. The reforms should be proposed by Spring 2017 and implemented as soon as possible thereafter.
> 2. Network owners should be incentivised by Ofgem to use storage (and other sources of flexibility) as a means of improving the capacity and resilience of their networks as part of a more actively managed system.[84]

While #1 above requires Ofgem and DECC to develop a "smart systems route map" by spring 2017, #2 does not appear to require Ofgem to do anything other than monitor its existing incentives under the RIIO framework.

New York

Meanwhile, across the Atlantic, in a February 2015 order NY's Public Service Commission

> …decided that utility affiliates could own DER and utility DSP operators could only own DER under certain circumstances. In making such determination, the Commission noted that it generally did not favour utility ownership and that it was persuaded that unrestricted utility participation in DER markets presented a risk of undermining markets more than it enhanced the potential for accelerating market growth. Thus, the Commission authorized such utility ownership under four circumstances: where 1) procurement of DER has been solicited to meet a system need, and a utility has demonstrated that competitive alternatives proposed by non-utility parties are clearly inadequate or more costly than a traditional utility infrastructure; 2) a project consists of energy storage integrated into distribution system architecture; 3) a project will enable low or moderate income residential customers to benefit from DER where markets are not likely to satisfy the need; or 4) a project is being sponsored for demonstration purposes.[85]

Translated into the jargon of Australia's NEM, these four exceptions might equate to the following:

1. A grid-side network-owned storage project has been subjected to a RIT process and found to be cheaper than other augex or non-network solutions.

2. As for 1 above.
3. No equivalent, thanks to the absence of any social objective in the NEO.
4. The project is undertaken as part of the network's DMIA.

Where utilities chose to invest in DER, they are required to prepare codes of conduct, "especially to prevent the possible misuse of inside information", which are similar to the content of the AER's draft Ring-Fencing Guideline.

New Zealand

The NZ Commerce Commission has been undertaking an inquiry into "input methodologies", including emerging technologies. In its early work it appeared to be taking a line different to other regulators, re-defining regulated services by including in that definition emerging technologies, such as batteries that would be situated beyond the point of supply. Consumer-side batteries could be added to networks' RABs

> …subject to the allocation of value between different regulated activities and between regulated and unregulated activities. Similarly, operating costs associated with batteries beyond the point of supply could be allocated to the regulated service using the cost allocation [input methodology].[86]

Naturally, retailers demur, with the Electricity Retailers Association arguing that "This unnecessarily increases the potential scale and scope of the regulated monopoly business by including assets and goods/services that can be provided by a competitive market."[87]

CEPA report

The CEPA report for the ENA/CSIRO Network Transformation Roadmap also surveys the regulatory landscape in California, New York and the UK. Cognisant of the different industry structure in the US, it makes a number of worthwhile observations (some of which have been quoted earlier in this report) of particular relevance which are worth summarising:

- Regulators are providing, or moving to provide, a 'return' on alternative solutions (predominately operating expenditure [opex]) to poles-and-wires, in order to neutralise networks' incentives across these options. There is a range of project based incentivisation (NY REV and proposed for California) and total expenditure (Ofgem).
- Most regulators are taking a risk-averse, but flexible approach to allowing networks to offer services that may become contestable. They are allowing DER, particularly storage, to be owned in a limited way, but are encouraging networks to source these services from third parties.
- Approaches to risk allocation are similar: the RAB is either legally protected or there are high levels of assurance around recovery of past costs; networks purchasing services from third parties rather than owning the assets themselves is seen as a way of transferring risk. Although Ofgem's approach to third party competition for 'core' network services has been to transfer the risk to customers by providing guaranteed revenue (as long as performance is appropriate).
- The regimes are becoming more complex as the industry transforms. While there is some significant 'refocusing' of regulatory frameworks, some of the added complexity appears to be the result of layering new arrangements on top of the existing frameworks. [88]

APPENDIX 2

NETWORK BATTERY PROJECTS[89]

	PROJECT	PURPOSE	$ + TIMING	FUNDING/ PARTNERS	NOTES/OUTCOMES
CONSUMER SIDE					
Ausgrid	65 X 5kW in Newcastle homes	?	2011-13? trial	Smart Grid, Smart City	
AusNet	**Residential Battery Storage Trial** "The project delivered an integrated residential storage solution to ten customers comprising of: • batteries (6.6kWh lithium-ion); • an inverter/charger (3kW peak); • programmable energy management systems; and • a communication system. The storage systems were installed in combination with solar PV (either 1.2kWp or 3kWp). All of the battery systems had internet connectivity to enable remote changes to system settings, retrieval of data and manual control of system operation."	"To investigate the potential of residential battery storage to: • flatten residential customer demand profiles, • manage the peaks in network demand that are driven by residential customers, • improve the integration of residential solar power into the network, and • assess the financial benefits of battery storage to the network and to customers."	2012-2015	DMIA	"Ten participating customers were selected to form a diverse demographic base with different consumption levels ranging from 7 kWh (below average) to 51 kWh (above average) per day. Nine of the customers were located in the AusNet Services distribution network and were on a two-part network tariff with peak and off-peak components." "Combining the maximum customer benefits of $3,500 with the potential network peak demand benefits of $3,300 yields a combined present benefit of $6,800. This falls some way short of the 2018 forecast total cost of $10,700. However, the shortfall could feasibly be made up through either non-financial customer benefits, benefits that vest with other parties such as energy retailers, or further technology cost reductions over a period of around 5 years."
Energex	**Battery Energy Storage Systems (BESS)** 1. A pilot demonstration of residential and commercial BESS installations at different sites, including the initial site at our EsiTrain	1. To provide insights into how customers configure and use battery systems. 2. To explore the possibility of accessing and remotely controlling BESS at certain	1. 2016-2018. 2. From late 2016.		

	facility at Rocklea. (Partnered with Sunverge, Tesla, Reposit and SolarEdge.) 2. A market-based trial in cooperation with vendors who are selling BESS to customers in selected areas in SEQ.	peak times (DLC).			
Ergon	**Residential Utility Support System (RUSS)** 10 advanced "smart-network enabled" 20 kWh lithium-ion battery storage systems within an urban network in Townsville.	"These trials were designed to demonstrate the effectiveness of VAR-controlled energy storage systems in reducing peak demand, improving supply reliability and quality and maintain network voltage regulation, particularly in locations with high concentrations of Distributed Energy Resources (DERs)."	2011-2013	Ergon	"The four quadrant VAR control worked well to manage customer PV voltage rise and peak load voltage drop, improving customer voltages by up to 12V. The trial also demonstrated that battery failures provided significant insight into the challenges of new lithium-ion battery technologies. Time scheduled peak management were shown to have limited success at the distribution level, with smaller customer numbers, the diversity at a distribution level resulted in the distribution level peak being far more variable than the overall network peak. Despite continuous monitoring of distribution loads and significant storage, time scheduling of peaks for battery discharge resulted in relatively poor coincidence."
Ergon	**Integrating Network Tariffs and Customer Owned Distributed Energy Resources** 4 systems tested on 10 adjacent homes in a Townsville street.	To test battery storage systems, home energy management systems and alternative tariffs	2015-	Qld Dept of Energy and Water Supply; DMIA.	"There are a significant number of residential battery energy storage systems (BESS) available in Australia. Due to limited standards in this area, the quality of the systems was found to be very variable and there were issues identified with compliance with existing standards. A number of the suppliers did not have a good understanding of how the BESS operated and had only considered how they responded to the shifting of renewable energy to maximise PV energy. The control systems for the BESS were also found to vary significantly, with little consistency in how they operated. Most systems offered little more than solar shifting and a basic time of use response function and only considered energy management to and from the batteries, and not the actual household energy use. The field trials are still ongoing, and in the locations where time of use is currently being trialled, this has resulted in customers being able to respond more rapidly, reducing peak load. Energy interested customers in the trial have also used their Home Energy Management Systems (HEMS) to manage better their overall energy use."

Essential	200kWh at Bega Library (with solar)	peak demand dispatch, reduction in fossil generation	2012	DMIA?	
Essential	**Networks Renewed**	Assessing & overcoming technical challenges related to inverters to allow networks to use batteries for their purposes – ancillary services, capex alternatives etc	2016-18 $2M	ARENA, ISF	
Powercor Energy Solutions*	Tesla Powerwall installations	"Save on bills. Take control of your energy usage. Reduce your carbon footprint."	2016+	Retail	
SA Power Networks	100 x 6.4 kW Tesla & Samsung batteries with software from Reposit	Peak demand reduction to prevent need for network upgrades	2016+	Internal?	minimum grid consumption of 4,000kWh a year (or 2,500kWh if they already have solar)
TasNetworks	**CONSORT Bruny Island** 40 homes; solar + batteries + EMS by Reposit Power	The households can supply energy to the island's mini-grid during the busy holiday season, when the population swells and electricity demand rises. This will relieve stress on the undersea cable supplying the island and reduce the need for expensive diesel-fuelled generators. It will also reduce TasNetworks' operational costs on the island, while rewarding consumers for their investment and support.	2016+ $8M	$2.9 from ARENA With ANU, U Tas, U Syd	
TransGrid	"NSW-based Transgrid has revealed plans to install a number of 1MW-sized battery storage systems at commercial customers, in a major push into smaller, grid-scale energy storage."	"We'd like to use storage to address network capacity limits – which are only hit several times year when things get tight… Once we get into this space, we can take learnings from the installation, the performance and the algorithms … and start to think how to unlock larger scale applications – not just to address network capital expenditure and the opportunity to defer that spending, but also to look at some edge of grid possibilities."			http://www.solarchoice.net.au/blog/news/nsw-transgrid-network-install-1mw-battery-banks-commercial-customers-100616

United	**Resi virtual power plant (VPP)**	peak demand reduction (augex alternative for capacity constraints)	2010-2015	DMIA	
MICROGRID					
AusNet	AusNet is to install between 3kW and 4.5kW of rooftop solar and 10kWh of battery storage on each of 14 homes in the outer eastern suburb of Mooroolbark…	… chosen because the homes are typically suburban, and because AusNet has a network constraint it thinks it can solve with distributed energy (solar and storage), and because the network configuration means that it is relatively easy to take them off the grid.	2016-17	?	The AusNet trial in Mooroolbark will be the first… to take a group of existing suburban homes completely off the grid. AusNet says it is in talks with other towns and communities about similar projects. "We've developed a control system that will monitor and manage energy flows within the mini grid," Ficca says. "This system will enable the energy that is stored in batteries to be shared between houses, based on the needs of the individual houses, the diversity of customer loads within the mini grid and the needs of the network." http://www.greensync.com.au/mooroolbark-community-mini-grid/
Horizon	**Onslow** 5.25 MW gas-fired power plant, with a mix of distributed and utility-scale solar, to be coupled with battery storage.	" Australia's largest solar and storage-based microgrid…will include the ability for consumers to trade power with each other within the micro-grid… the current dependence on gas has raised some "reliability" issues, but the new micro-grid will lower costs to consumers, and remove much of the large state subsidies that have traditionally supported fossil fuel power in the state's north west."	2018	$70 M from WA Govt plus $? From Chevron Wheatstone	http://reneweconomy.com.au/2016/w-plans-australias-biggest-solarstorage-micro-grid-onslow-39857
Jemena	Modelling exercise	"We clustered groups of 5 households and assessed the potential for an integrated micro-grid to achieve our objectives (more solar/less cost/flatten demand) compared to individual solar/battery roll out."	2015-16	ARENA MEFL GreenSync	

Powercor	**Newstead** MOU with Energy for the People	"Powercor… imagines it will be a mixture of rooftop solar and localised storage, with some "community" size facilities such as a 2MW solar plant and a large-scale storage facility. Energy efficiency – and helping the township reduce the amount of electricity it consumes - will also play a critical role, as will real time data around energy consumption."	2016>	$200,000 Vic Govt seed funding for town?	
Western Power	White Gum Valley: 80 apartments, 150kW of solar and 300kWh of battery storage.	Grid-connected micro-grid or embedded network that allows all tenants access to the solar and storage facilities. The power bills will come to individual tenants from the body corporate, (possibly via an energy services company), which then seeks a return on its investment, but is likely to be able to offer significant savings to the residents.		ARENA $1M	Includes P2P trading. Collaboration between Curtin University, project developer LandCorp, grid operator Western Power, along with the Low Carbon Living CRC, the City of Fremantle and Solar Balance.
NETWORK SIDE					
Ausgrid	60kW at Newington	Managing summer peak demand	2014-15 trial	DMIA	
AusNet	**Grid Energy Storage System (GESS)** 1 MW/1 MWh containerised units to supply power to around 300 homes in Thomastown, Melbourne, during peak periods, with the battery being recharged during off-peak periods.	"Manage network peak demand, improve power quality, provide islanded supply to local network customers, and defer network upgrades."	2014-16	DMIA + AusNet	"During the summer of 2014-15, the GESS was put through a number of performance trials including local peak lopping, power factor correction and voltage droop functions while in grid connected mode. These trials successfully proved the performance of the system in real-world conditions, whilst also building the understanding of these systems with the grid network operators and planners. A further trial plan has been planned for the 2015-16 summer period around power quality support, feeder demand management and working in island mode."
ElectraNet	**Energy Storage for Commercial Renewable Integration in South Australia (ESCRI-SA)** 10MW, 20MWh lithium-ion battery storage	Balancing the output of wind and solar farms, keeping the lights on in a blackout, reducing transmission losses, and providing	Study only $20M	ARENA, AGL, ElectraNet and Worley	"In Phase 1 of the project, the Consortium has concentrated on the business case of developing such a storage asset, and the associated issues that surround such assets. In Phase 2, which will depend on the outcomes of Phase 1, it is hoped to build, test and

	facility next to the 91MW Wattle Valley wind farm on the Yorke Peninsula	frequency services to keep the grid stable.		Parsons	trial such an asset at utility scale."
Ergon	**Grid Utility Support System (GUSS)** 20 X 100 kWh containerised units	Managing peak load, power quality + reliability on remote SWER lines	2013-2016	DMIA, Ergon	"The product trialled for this project has proven highly successful. GUSS is able to resolve short term capacity issues on SWER networks. Subsequently, numerous SWERs on Ergon's network have been identified as being able to bene t from GUSS. A commercially developed product has now been delivered, and is in the process of being rolled out across the network."
Ergon	**Centralised Energy Storage System (CESS)** 200 kWh, containerised	"CESS will develop a platform for the development of a variety of control methodologies to respond to various needs from the Ergon Energy network – this includes energy storage opportunities both for the network and for our isolated power system networks."	2014-2016	DMIA, Ergon	"The outcomes of this project are still to be determined as it is still in the development and implantation phase."
Powercor	Battery in Buninyong 2MW Li-ion unit near Ballarat	"Reduce stress on the network on peak days, improve reliability, and reduce capital expenditures".	2015-16	DMIS (DMIA?) + Powercor	
(SA Power Networks)	Proposed microgrid trials at Hawker and Elliston	Reliability	$2.8 m Rejected by AER in final determination	Augex in RAB	DID NOT PROCEED
TransGrid	**iDemand** "… a hybrid demand management system incorporating both embedded generation and storage at its western Sydney site. The iDemand system consists of a 400kWh Lithium polymer battery, 53 kW of polycrystalline silicon and 45kW of thin film cadmium telluride solar panels, energy	"iDemand is a pilot project aimed at facilitating demand management related research in Australia and to engage consumers on demand management."	2013-2014		Since the projects launch in November 2014, TransGrid has received six research proposals on topics such as real time battery dispatch algorithm to minimise peak demand, and battery degradation modelling. It is expected that some of the research conducted will result in better understanding of how to integrate batteries as part of a demand management solution. The iDemand website has been a drawcard for researchers as the website allows free access to data since November 2014 for solar

	efficient lighting, with a web portal that updates key system output data every 5 seconds."				generation battery dispatch, site load, weather and lighting load at one minute intervals. The peak demand on site has been reduced by more than two-thirds when batteries are dispatched simultaneously with the solar panels generating at capacity."
United	"7 constrained distribution substations identified for economic deployment of storage at lower cost than network augmentation"	"feeders experiencing voltage issues or requiring capacity augmentation"	$2.5 m 2015-2020	augex in RAB (earlier asked AER for open or revenue pass-through)	
MIXED					
Western Power	"Western Power says it is seeking tenders from third parties that could include solar and storage and community energy as it seeks to avoid spending $30 million in [Mandurah]."		< $30M	Non-network alternative to augex	http://reneweconomy.com.au/2016/western-power-seeks-solar-storage-community-options-to-avoid-network-spending-43973

APPENDIX 3

AER SERVICE CLASSIFICATIONS AND OUR PREFERRED OPTION

The AEMC has identified the AER's service classification system as a key variable in the regulation of batteries, since it is the main regulatory determinant of whether battery services will be regulated or contestable. The AEMC has proposed that contestable services should only be provided by regulated networks via ring-fenced businesses or by third parties. It recommends that all consumer-side services be unregulated and contestable, and that "Storage used to provide services on the network would be subject to the AER's usual service classification."[90]

It is therefore worth discussing how this system works, as well as how this paper's preferred regulatory option for grid-side batteries might be applied. Essentially, the service classification regime and related cost allocation, ring-fencing and shared asset guidelines will influence whether battery services are regulated network services that can be added to RABs as capex or are, instead, obtained as opex on the open market.

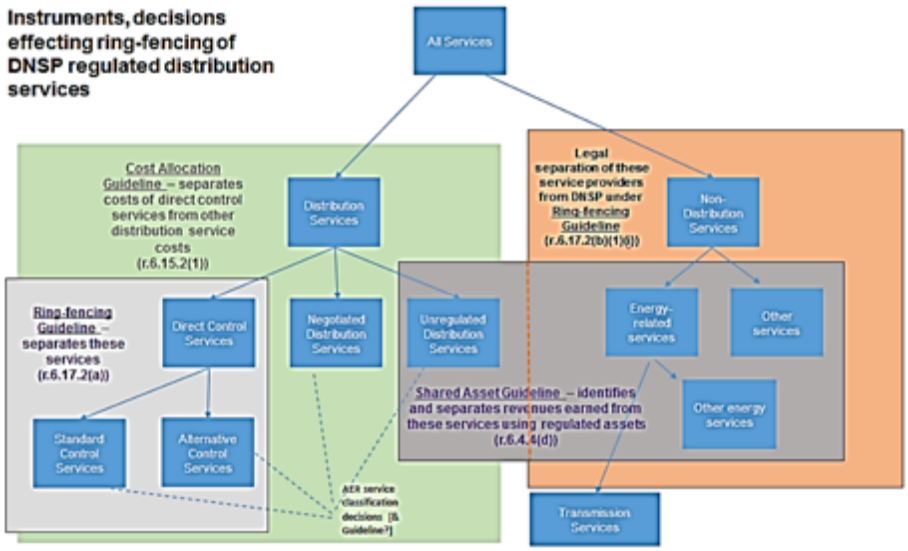
A3.1 How it works

As shown in the figure below,[91] the first level of disaggregation is between distribution and non-distribution services. As the EC explains,

> Under the NER, a distribution service is a service provided by means of, or in connection with, a distribution system.
>
> In classifying distribution services, the AER must have regard to the 'form of regulation' factors in the NEL9. These factors provide guidance to the AER in deciding whether a service has the characteristics of a service that should be regulated, such as barriers to entry, the relative market power of networks and customers, the availability of substitute services, and the information available to networks and customers in coming to agreements.[92]

Arbitraging, for instance, falls into the latter category. There is currently debate about whether the meter constitutes the boundary of a distribution service; this is likely to be the subject of a rule change to clarify. All non-distribution services are unregulated and contestable or competitive. Batteries are an asset that can provide multiple services that fall into various categories – e.g., a consumer-side battery could be partly used to provide network support to manage peak network demand, which would be a distribution service.

Figure A3.1



At the second level of disaggregation, distribution services are divided into three types. Direct control services are made up of standard control services (SCS) and alternate control services (ACS). A direct control service is defined in S.2B of the NEL as "a service the price for which, or the revenue to be earned from which, must be regulated under a distribution determination or transmission determination". A SCS is defined in the NER as a "direct control service that is subject to a control mechanism based on a Distribution Network Service Provider's total revenue requirement", while an ACS is defined as "A distribution service that is a direct control service but not a standard control service." In practice, the AER generally defines a relatively broad "network service" that covers all things directly related to transporting electricity to consumers and classifies this service as an SCS.

The AER currently regulates this service through a revenue cap, which allows DNSPs to recover the efficient costs (capex and opex) of providing this service through general network charges paid by all consumers. A range of services like public lighting, metering and other services that are provided to individual customers are classified as ACS and are subject to a price cap for each service. SCS costs are recovered through the overall revenue cap, while ACS costs are recovered through service-specific prices.

Other distribution services are defined as "negotiated network services" under Clause 2C of the NEL or are unregulated services. The latter category includes new smart meters from 1 December 2017 and connection services in NSW.

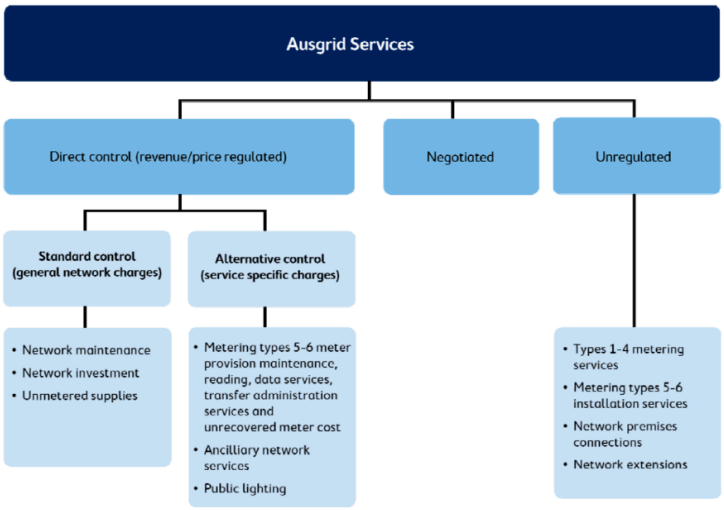
Negotiated and unregulated distribution services and non-distribution services must be ring-fenced from regulated direct control services. Which services fall into which category is determined as part of the framework and approach (F&A) process, which begins about one year before the formal commencement of the five yearly revenue determination process.

The underlying logic appears to be that any distribution service which could be provided through a competitive market is generally classified as unregulated, whereas services considered by the AER to be best provided by monopoly network businesses are regulated as direct control services. Similarly, all non-distribution services can be provided by the competitive market and are therefore not regulated. Allied businesses that offer unregulated distribution services or non-distribution services must be ring-fenced from the network business itself. According to the AER,

> …where an NSP uses DER to offer a service into a competitive market, such as the wholesale market for electricity, the service would not be classified as a direct control service and therefore would be ring-fenced under the approach proposed in this paper.[93]

Here is how the current service classification is applied in general terms to Ausgrid's distribution services:[94]

Figure A3.2



Particular services are allocated to service groups or activities. For instance, "network investment" includes various activities related to planning, designing and constructing the network.

Finally, at the third level of disaggregation, in the revenue determination process networks use the AER's cost allocation guideline to allocate costs between standard control, alternative control, negotiated and unregulated services. That is, the "services" are determined as set out above and then the next step is to determine the efficient costs of providing those services, which is used to determine the regulated revenues and prices. The capex/opex issue is part of determining the efficient costs for each service.

As part of the revenue determination process, the AER also determines the efficient costs of providing standard control and alternative control services, which it uses to set the DNSPs' regulated revenues and prices. For standard control services, the AER determines the amount of opex and capex that an efficient DNSP would incur to provide those services. The AER uses those amounts, together with other inputs such as the cost of capital, to set an overall maximum amount of revenue that the DNSP can recover through its charges for standard control services.

Costs related to new or replacement assets are usually capex, while opex includes labour costs and the purchase of services from third parties. For example, the costs of providing a standard control "network service" could include capex for network solutions in certain areas (eg, building a new substation) as well opex for non-network solutions in other areas (paying an embedded generator or battery provider to provide network support services to reduce peak demand on the network as an alternative to building new network assets).

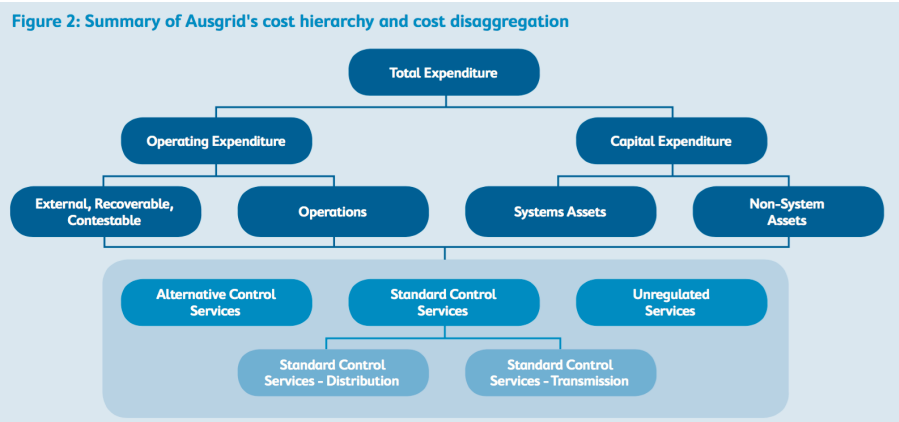
Using batteries to reduce upstream peak demand on the network, for instance, could be capex if the DNSP owns the battery or opex if the DNSP buys network support services from a third party that owns the battery. To add to the complexity, some costs are shared between different service classifications, for example where the network owns a battery that is used to provide both standard control and unregulated services.

Capex becomes part of the RAB at the start of the next five year regulatory period and is depreciated over the life of the asset (which is determined by the AER and can be up to 30 years). This means that capex is gradually recovered over time as the asset depreciates rather than being recovered from consumers up-front. As a result, the DNSP earns a regulated rate of return on the RAB as part of the AER's determination of the revenue cap for standard control services.

By setting a revenue cap, the AER does not dictate how much capex and opex the DNSP is allowed to spend, or what proportion of each it must spend. The revenue cap is based on the AER's estimate of the efficient costs of providing the service and various incentive schemes reward the DNSP if it spends less than the revenue cap, with the DNSP keeping a set percentage of the savings and sharing the rest with consumers through lower future network charges.

Here is how this final stage currently applies to Ausgrid through its cost allocation method:[95]

Figure 2: Summary of Ausgrid's cost hierarchy and cost disaggregation



Classifying battery services as regulated does not automatically require them to be obtained via capex; however, classifying them as unregulated automatically requires them to be obtained via opex, since they cannot be added to RABs.

A3.2 Will it work for batteries?

As stated above, in relation to grid-side batteries the AEMC's preferred approach is that "Storage used to provide services on the network would be subject to the AER's usual service classification."[96] In its ring-fencing preliminary positions paper, the AER's position was effectively that, subject to the normal planning and investment processes such as RITs, networks should be able to determine whether regulated services (i.e., those classified as direct control) to be provided by batteries are procured as capex assets and added to their RABs or as opex services from third parties or ring-fenced businesses; whichever solution is the most economically efficient (or profitable). Unregulated services provided by batteries would need to be procured from ring-fenced businesses or third parties.

This is our Option 2. The main issue with it from a service classification perspective is its complexity. Some battery services will be standard control services, while others may be alternate control services, unregulated distribution services or non-distribution services. While most attention to date has focused on the implications of this complexity for ring-fencing, the cost allocation and shared asset guidelines will also be involved, potentially requiring accounting changes each five year regulatory period as value streams come and go, rise and fall. Putting aside the inevitable administrative burden and the question of whether the AER is adequately resourced to oversee this dynamic landscape, even if networks themselves are able to negotiate this minefield it is likely to represent a significant hurdle for new entrants into the battery market.

Conversely, under our preferred Option 3, here is how the service classification regime and related cost allocation and ring-fencing guidelines might apply:

Table A1: Proposed grid-side battery service classifications

Battery service	**Service classification (current regime)**	**Service classification (preferred regime)**	**Cost allocation (preferred)**
1. Managing peak demand (reduced augex & repex compared to other network solutions)	Distribution Standard control	Distribution Unregulated	Opex recovered through revenue cap OR N/A – ring-fencing means the network cannot directly provide this service
2. Providing backup for isolated feeders (alternatives to other augex to respond to increasing localised peak demand or repex to maintain reliability on fringes of grid)	Distribution Standard control	Distribution Unregulated	Opex recovered through revenue cap OR N/A – ring-fencing means the network cannot directly provide this service
3. Maintaining power system security (managing intermittency of generation from wind + solar farms)	Distribution Standard control	Distribution Unregulated	Opex recovered through revenue cap OR N/A – ring-fencing means the network cannot directly provide this service
4. Selling ancillary services into wholesale market	Non-distribution Unregulated	Non-distribution Unregulated	N/A – ring-fencing means the network cannot directly provide

(eg, frequency + voltage control)			this service
5. Arbitraging energy (buying & selling energy at different times, storing it in the interim)	Non-distribution Unregulated	Non-distribution Unregulated	N/A – ring-fencing means the network cannot directly provide this service

A3.3 Implementation

Our preference for the *No RAB, all opex* option is made in the context of the existing service classification system. However, as suggested earlier, to implement it would require a rule change to allow the AER to either

- treat battery services uniquely in the service classification process as unregulated distribution services (our implementation solution 1); or
- classify services 1-3 above as Distribution – Unregulated whichever way they are procured (our implementation solution 2).

If the AER's ring-fencing guideline is so tightly constructed that networks are likely to conclude that complying with it by obtaining SCS from batteries with capex and unregulated services (ancillary services and arbitraging) from batteries with opex from ring-fenced businesses is likely to create a significant administrative and cost burden, they may therefore prefer to obtain all battery services from ring-fenced businesses and third parties. However, because it relies on predicting network behaviour this is a risky solution from a consumer perspective and offers no guarantees of a successful outcome for them.

One further option available with minimal reform of the rules would be for a RIT-like process to apply specifically to battery investments (most of which are well under the current $5 million materiality threshold) requiring networks to procure battery services as opex only as the default option, with the capex option permissible with justification. But it is unclear whether the AER would be allowed to adopt this approach under the current regime, which requires it to regulate services rather than assets.

A3.4 Alternatives

As this discussion reveals, the opacity and complexity of the current rules, in which service classifications overlap with the cost allocation, ring-fencing and shared asset guidelines, creates a web of overly complex regulations that are almost impenetrable to outsiders. A system which is only comprehensible to longstanding network staff and regulators is inherently no longer fit for purpose for a decentralised energy system in which prosumers and their agents need good access to information in order to make informed and efficient decisions about how to invest in and market their generation and storage.

In our view, this system is ripe for review and reform.[97] The aim of such a review could be to potentially simplify the classifications to only two (regulated network services and unregulated contestable services). The review could even consider scrapping this system for a new system which is more suitable to a decentralised energy system with a high degree of competition and innovation. We share the EC's view that S 6.2.1 (Classification of distribution services) and 6.2.2 (Classification of direct control services as standard control services or alternative control services) of the rules in particular are in need of reform to allow for a more dynamic market with greater contestability of new products and services.

For instance, it has been suggested that a system that inherently favours capex over opex, recently reformed to try to level the playing field through incentives like the CESS, should be replaced by a "totex" approach (as adopted by Ofgem and recommended in the CEPA report for the ENA and

CSIRO) in which all expenditure, capex plus opex, is capitalised equally; the onus is then on the network to decide how best to provide the service. As CEPA explains totex,

> Under a building blocks approach both opex and capex are treated the same, and combined for output assessment purposes, with a pre-determined capitalisation rate. This approach helps to equalise incentives, as there is no differential treatment between opex and capex and outperformance is treated the same regardless of expenditure type. If this is coupled with strong incentives, then it can help encourage innovative solutions as well as existing alternative non-traditional capex ones.[98]

This would require a wholesale review of the rules to cater for a more dynamic, two-way energy system, but such a review appears to have the EC's blessing when it argues for a review of the F&A and service classification processes as well as their content:

> …the rules were developed as part of a process to transfer economic regulation from jurisdictional regulators to a new national regulator.
>
> Further, in a less dynamic market a more static or conservative approach to classification of services may have been appropriate. However, in a changing marketplace changes to the rules to allow the AER more discretion on re-classification of services would allow a more proactive approach to moving services out of economic regulation, and would also likely stimulate greater debate in the market on potential for contestability of services.[99]

GLOSSARY

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APR	Annual Planning Report
ATA	Alternative Technology Association
CALC	Consumer Action Law Centre
CESS	Capital Expenditure Saving scheme
CEC	Clean Energy Council
COAG EC	Council of Australian Governments Energy Council
CUAC	Consumer Utilities Advocacy Centre
DAPR	Distribution Annual Planning Report
DER	Distribute Energy Resources
DLC	Direct load control
DMIA	Demand Management Innovation Allowance
DMIS (or DMEGCIS)	Demand Management Incentive Scheme
EBSS	Efficiency Benefit Sharing Scheme
ECA	Energy Consumers Australia
ENA	Energy Networks Association
DNSP	Distribution Network Service Provider
ENA	Energy Networks Association
F&A	Framework and Approach
FiT	Feed-in Tariff
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electricity Rules
PIAC	Public Interest Advocacy Centre
RAB	Regulated Asset Base
RAPS	Remote area power systems
REV	New York State, Reforming the Energy Vision
RIIO	UK Ofgem's Revenue = Incentives + Innovation + Outputs model
RIT-D	Regulatory Investment Test - Distribution
RIT-T	Regulatory Investment Test - Transmission
TAI	The Australia Institute
TEC	Total Environment Centre
TNSP	Transmission Network Service Provider

NOTES

[1] State Of New York Public Service Commission, Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, May 19, 2016, 5.
[2] Here the two terms are used interchangeably, while noting that energy storage is wider, since it can involve technologies such as pumped hydro; but the current urgency around regulatory reform has been brought about by the rapidly increasing affordability and thus popularity of small lithium-ion consumer batteries and a variety of larger grid-side battery technologies. Li-ion is but one form of chemical energy storage; other forms of storage include mechanical (eg, flywheels); fluid storage (pumped hydro or compressed air); electromagnetic systems (eg, superconducting magnets); hydrogen; and advanced batteries such as supercapacitors. (See Mountain and Crossley for more)
[3] The N+B project reference group is composed of representatives from the following organisations:
Total Environment Centre
Energy Consumers Australia
Consumer Action Law Centre
Public Interest Advocacy Centre
South Australia Council of Social Service
St Vincent de Paul Society
Alternative Technology Association
Ethnic Communities Council
Clean Energy Council.
[4] Thanks especially for their feedback to industry collaborator Adrian Kemp of HoustonKemp; Richard Owens, Senior Director, AEMC; Ben Davis, Senior Advisor, AEMC; and Gerard Brody, CEO, Consumer Action Law Centre.
[5] See http://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/ring-fencing-waivers/energex-ring-fencing-waivers-2016 and http://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/ring-fencing-waivers/ergon-energy-ring-fencing-waiver-2015.
[6] As the AEMC puts it, "the current regulatory framework appears to allow network businesses to own and control energy storage, subject to some clarification of how the services provided by the storage devices would be classified" (AEMC, *Integration of Storage: Regulatory Implications, Final report*, December 2015, 5).
[7] This is an assumption based on the current typical warranty period for consumer batteries.
[8] Bruce Mountain, *Batteries and electricity network service providers in Australia: regulatory implications,* 2015.
[9] Mountain, 5.
[10] Mountain, 6.
[11] Mountain, 6.
[12] Mountain, 6.
[13] AEMC, *Integration of Storage: Regulatory Implications, Final report*, December 2015.
[14] AEMC, 2015, i.
[15] AEMC, 2015, ii.
[16] AEMC, 2015, Box 1, iv.
[17] AER, *Electricity Ring-Fencing Guideline: Preliminary Positions Paper*, May 2016.
[18] AER, *Electricity Ring-Fencing Guideline: Preliminary Positions Paper*, May 2016, 23.
[19] According to the AEMC, "Where storage devices provide a mixture of regulated activities (substituting for traditional network services) and competitive energy services, then ring-fencing, cost allocation and shared asset guidelines would apply", AEMC, 2015, 5.
[20] ENA and CSIRO, Electricity Network Transformation Roadmap, Overview, 2: http://www.ena.asn.au/sites/default/files/electricity_network_transformation_roadmap_overview.pdf.
[21] Cambridge Economic Policy Associates, *Future Regulatory Options for Electricity Networks*, Energy Networks Association (ENA) and Commonwealth Scientific and Industrial Research Organisation, August 2016, i.
[22] CEPA, iii.
[23] CEPA, iv.
[24] CEPA, viii.
[25] Energeia, *Australian Residential Solar Storage Analysis - Part I - An Enthusiast's Market*, February 2016.
[26] ATA, *Life After FiTs*, May 2016.
[27] Steve Blume, ed, *Global Energy Storage Market Overview & Regional Summary Report 2015*, Australian Storage Council, 2015, ES.
[28] AEMO, *Emerging Technologies Information Paper*, 2016, 4.
[29] Mountain, 2015, 44.
[30] For examples in each category, see Appendix 2.
[31] Draft results supplied in confidence by ISF.
[32] COAG Energy Council, Meeting Communique, 4 December 2015.

[33] COAG Energy Council, Rule change request to promote the contestable provision of services from emerging technologies, August 2016, 3.
[34] COAG Energy Council, Rule change request, 4.
[35] COAG Energy Council, Rule change request, 9.
[36] AER, *State of the Energy Market 2015*, 78.
[37] Sources include Rocky Mountain Institute, Fitzgerald, Garrett, et al, *The Economics of Battery Energy Storage: How multi-use, customer-sited batteries deliver the most services and value to customers and the grid.* Rocky Mountain Institute, September 2015: http://www.rmi.org/electricity_battery_value; Entura for Clean Energy Council, Grid Support: Revealing midscale generation and storage potential, December 2015: www.cleanenergycouncil.org.au/fpdi; and TAI, 6-7.
[38] F G Hilmer et al, *National Competition Policy*, 1993, 1.
[39] George Yarrow and Euan Morton, Applying Hilmer Principles in Changing Energy Markets: http://www.ena.asn.au/competition-policy-and-network-regulation-changing-energy-markets.
[40] AEMC, 2015, II.
[41] CSIRO and Energy Networks Association 2015, *Electricity Network Transformation Roadmap: Interim Program Report*, 110; see also Yarrow and Morton.
[42] AusNet Services, Demand Management Case Study: Residential Battery Storage Trial, March 2016, 12.
[43] On excessive profit margins in the retail market, see, e.g., Bruce Mountain, *Australia's retail electricity markets: who is serving whom?* August 2016.
[44] On the lack of effective competition in the SA wholesale market, see, e.g., Melbourne Energy Institute, *Winds of change: An analysis of recent changes in the South Australian electricity market*, August 2016.
[45] Essential Research for Energy Consumers Australia, Energy Consumer Sentiment Survey Findings, July 2016, 2-4.
[46] Essential Research for Energy Consumers Australia, Energy Consumer Sentiment Survey, July 2016, 35.
[47] Dan Cass, *Securing Renewables: How batteries solve the problem of clean electricity*, The Australia Institute research report, April 2016, iv.
[48] Cass, 12.
[49] While grid-side batteries are useful to balance the intermittency of renewable generation, they can also be used to arbitrage the low cost of overnight coal generation. The latter constitutes a net environmental negative.
[50] The need for networks to respond to policy drivers promoting renewable energy and reducing Australia's greenhouse emissions is a feature of the ENA/CSIRO Network Transformation Roadmap process, but this is different to taking a proactive stance in support of the need for action on climate change, which is any business's prerogative; in the retail space, contrast Powershop, for instance.
[51] Intending zero net energy or Znet communities currently include Yackandandah and Newstead in Victoria, Uralla and Tyalgum in NSW and Kangaroo Island in SA.
[52] AEMC, 2015, 12.
[53] Mountain, 6.
[54] AEMC, 2015, ii.
[55] COAG Energy Council, Rule change request, 11.
[56] AEMC, 2015, 11.
[57] Clean Energy Council, Integration of Energy Storage: Regulatory Implications, Discussion Paper Submission, November 20015, 6.
[58] In view of TEC, CALC and CUAC's recent experiences with rule change requests, we propose this reform with great trepidation, however. Simply put, in spite of our best efforts no rule change proposed by small consumer groups has ever been substantially successful. Here we exclude TEC's DMIS rule change request, which closely followed the AEMC's own draft specifications in its Power of Choice final report, and which was also closely aligned to a COAG Energy Council request.
[59] AEMC, 2015, 7.
[60] AEMC, 2015, iv.
[61] AEMC, 2015, 13.
[62] Mountain, 71.
[63] Mountain, 73.
[64] Mountain, 73.
[65] Mountain, 76.
[66] ECA, Principles for the Integration of Energy Storage November 2015, 3-4.
[67] COAG Energy Council, Rule change request, 9.
[68] COAG Energy Council, Rule change request, 9.
[69] Pers. comm. AEMC staff.
[70] AEMC, 2015, iv.
[71] AER, National Electricity Rules: Proposal to introduce new replacement expenditure reporting and planning arrangements to the Chapter 5 planning framework, 3.
[72] AEMC, 2015, vi.

[73] AER, *Electricity Ring-Fencing Guideline: Preliminary Positions Paper*, May 2016, 10-11.
[74] CEC, 2015, 8. The CEC's proposed solution is to "transfer the connection approval powers to an independent organisation [such as AEMO] with no commercial interest in the outcome." This sounds reasonable, but was not accepted by the AEMC.
[75] As the AEMC put it, "whether thresholds in the planning process (eg, for the RIT-T and RIT-D) remain appropriate in the face of changing technologies and more distributed energy resources, and whether any other information resources are necessary": AEMC, 2015, vi.
[76] See AEMC, 2015, 22-23.
[77] The NER define a generating unit as "The plant used in the production of electricity and all related equipment essential to its functioning as a single entity." Batteries could only be construed as producing electricity if one ignores the fact that the energy has already been produced elsewhere.
[78] Mountain, 39. With reference to the ensuing discussion in this paper, while the AEMC has made clear its view that "any system that exports electricity to the grid is a generating system", it invites a rule change request from any party wishing to clarify the definition. We take this to mean that it invites a much more limited Rule change request than one that seeks to introduce a unique and broader definition of energy storage.
[79] Penelope Crossley, "Defining the Greatest Legal and Policy Obstacle to 'Energy Storage'", *Sydney Law School Legal Studies Research Paper* No. 14/56, May 2014, 23.
[80] Crossley, 17.
[81] Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, May 19, 2016, 22.
[82] See www.ny.gov/rev4ny.
[83] Ofgem associate partner, energy systems, Andy Burgess, quoted in Lucinda Dunn, "Ofgem rejects calls to license energy storage," 14 April 2016: https://networks.online/gphsn/news/1000071/ofgem-rejects-calls-
[84] Government Response to Smart Power, undated, 2.
[85] State Of New York Public Service Commission Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. Order Adopting Regulatory Policy Framework and Implementation Plan, February 2015, 70: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={0B599D87-445B-4197-9815-24C27623A6A0}.
[86] ERANZ, Submission on Emerging Technologies - Workshop and Pre-workshop paper, February 2016, 3.
[87] ERANZ, Submission on Emerging Technologies - Workshop and Pre-workshop paper, February 2016, 18.
[88] CEPA, Text box 2, iii.
[89] A work in progress compiled from various sources including Energy Networks Association, *The Great Energy Quest: Case studies in Australian Electricity Storage*, September 2015. There are other grid-side storage projects planned (up to 40 MWh) which do not involve networks as active partners: see, e.g., World's biggest solar + storage projects planned for Australia: www.reneweconomy.com.au/2016/worlds-biggest-solar-storage-projects-planned-australia-95528. Retailers (eg, AGL and Synergy) are also getting involved on the consumer side with bulk, discounted projects.
[90] AEMC, 2015, iv.
[91] AER, *Ring-fencing Guideline Explanatory statement*, August 2016, Figure 1, 15.
[92] COAG Energy Council, Rule change request, 12.
[93] AER, *Electricity Ring-Fencing Guideline: Preliminary Positions Paper*, May 2016, 23.
[94] Ausgrid, *Framework and Approach 2019-24: Discussion Paper*, 6.
[95] Ausgrid, Cost allocation method, November 2013, 7.
[96] AEMC, *Integration of Storage: Regulatory Implications, Final report*, December 2015, iv.
[97] The EC rule change request highlights the need for review of the service classification regime – noting, for instance, that it combines functional and cost-recovery characteristics; see COAG Energy Council, Rule change request, 13.
[98] CEPA, xi.
[99] COAG Energy Council, Rule change request, 14.