Implications of network ownership of grid-side battery assets on competition in the Wholesale Electricity Market

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Background and objective

In 2019, changes were made to the Electricity Industry Act 2004 (Act) to explicitly allow Western Power to deploy distribution-connected storage devices in the South West Interconnected System (SWIS).

In 2020, changes were also made to the Energy Networks Access Code (2004) regarding some of the details concerning Western Power's responsibilities in deploying grid-side, including the information they would be expected to share about the need for and value of grid-side storage, and how revenue generated from the services of those assets – particularly any revenue generated in unregulated markets – would be shared with the network's customers who would be paying for those assets through their network charges.

In December 2020, the Australian Energy Council commissioned Oakley Greenwood to review the changes that had been made to both documents with regard to their likely impacts on competition in the provision of grid-side batteries and the services they can provide to the electricity supply chain. More specifically, our review was to include:

- Commentary on the changes that had been made from the perspective of their conformance with economic theory and the objective of the Electricity Networks Access Code
- Practical recommendations regarding specific activities that could be undertaken in implementing the Code that would assist in mitigating the negative impacts on competition.

Key findings concerning the impact of the changes on competition

Our analysis suggests that the changes to the Code are unlikely to lead to outcomes that are consistent with the overarching objective of the Code.

The key cause of this is the part of the New Facilities Investment Test – specifically Clause 6.52 (b) (ii) – which allows Western Power (WP) to recover the costs of grid-side battery investments based on their *potential* to produce net benefits. This, combined with the revenue sharing provisions related to multi-function assets (70:30 sharing of net incremental revenues), results in the financial flows that ensue from the adoption of a grid-side battery to differ, depending on whether WP or a third-party provider owns and operates the asset, **even for the same asset providing exactly the same economic benefit**.

This has the potential to:

- **Reduce dynamic efficiency:** This uneven playing field, to the extent that it disadvantages third party competitive providers, will disincentivise those parties (who may have otherwise been interested in investing in grid-side batteries and making their services available to various parts of the electricity supply chain) from competing to provide these service. Less competition means less innovation, less pressure to innovate, and generally, diminished economic efficiency in the long-term (dynamic efficiency).

- **Reduce productive efficiency and increase costs to consumers:** WP will be overly incentivised to invest in multi-function assets, relative to other types of assets, due to their ability to capture and retain either 100% or 70%[1] of the incremental (unregulated) revenue that can be generated from those types of assets, whilst also being guaranteed the recovery of 100% of the economic costs of installing those assets in the first place through the tariffs levied on the end customers using the network.

Moreover, the Code places an undue amount of reliance on potential regulatory interventions to overcome any potential issues. This is most apparent in EPWA's inherent assumption that:

- Any over-investment allowed into the RAB under the NFIT (as discussed above) will be identified and corrected by the regulator during any ex post review, and
- The Code provides the ERA the ability to implement ring-fencing arrangements if and as required[2].

Generally, regulation seeks to enact policies and principles set by a rule-making body and to put in place mechanisms that incentivise the regulated party to reveal its efficient costs of operation. The Code does not appear to do this in this case.

Notwithstanding this, the Code specifies several Guidelines that are to be developed by the ERA for implementing the various parts of the Code. Given that the changes to the Code have been approved and the issues described above are unlikely to be corrected through further amendments to the Code (at least for the time being), the details of these Guidelines represent the only way that the shortcomings of the Code can be ameliorated. It is important that this opportunity is used effectively while also reiterating and seeking re-consideration of the larger issues identified in this report regarding the changes that have been made to the Code.

1 The percentage depends on whether Western Power reaches the $1m materiality threshold for unregulated revenue.

2 Noting that our reading of the Code, as it relates to the ERA's ability to introduce ring-fencing arrangements for Western Power, is that there may in fact be some limitations on the ERA introducing ring-fencing in the context of a grid-side battery that is used to provide ancillary services and/or which is leased to a third party that provides services into a competitive market.

1. Background

We understand that changes were made to the Electricity Industry Act 2004 (Act) in 2019 to explicitly allow Western Power to deploy distribution-connected storage devices in the South West Interconnected System (SWIS), and that in 2020, changes were also made to the Energy Networks Access Code (2004) to, amongst other things:

- Increase information provision/transparency regarding the network conditions that could potentially be met through the deployment of grid-side battery storage
- Reduce administrative costs and asymmetric information related to grid-side battery opportunities
- Provide for the sharing of any revenue generated from the use of what are termed multi-function assets (e.g., grid-side battery storage) to provide services into unregulated markets, with its regulated customers.

2. Objective of project and report

2.1. Objective of this section

The objective this section is to outline the:

- Objective of the project;
- Process we undertook to complete this project;
- Caveats to this report; and
- Structure of the remaining sections of this report.

2.2. Objective of project

The Australian Energy Council (AEC) has requested that we provide a qualitative assessment of the impact on parties that currently or may in the future provide goods and/or services in the competitive portions of the electricity market that would result from the network operator being able to provide regulated and unregulated services from grid-side batteries. In addition, and to the extent deemed appropriate, we were asked to provide recommendations on:

- Measures that should be considered to prevent or mitigate any negative impacts on competition that could arise from Western Power providing unregulated services from grid-side batteries, including a prohibition on Western Power providing those services, and
- Measures that could be put in place that would put a positive obligation on Western Power to:
  - Engage with the market; and
  - Select the most appropriate (i.e., economically efficient) means for delivering the least cost and most efficient solutions for network system needs (e.g., reliability, stability and security), including procuring these services from third parties.
- Measures that could be proposed with regard to the activities to be undertaken in implementing the Code that could assist in mitigating some of the negative impacts on competition that had been identified.

2.3. Process undertaken to complete this project

As part of the development of this report, we have consulted with the following stakeholders:

- The Australian Energy Council ('AEC'), and its members
- Energy Policy WA ('EPWA')

2.4. Caveats

This report should be read in the context of the following caveats:

- Whilst this report reflects our interpretation of the Code and related regulatory instruments, it does not constitute a formal legal opinion
- While we have consulted with various parties including the AEC, individual AEC members that operate in WA and staff of EPWA, the interpretations, conclusions and recommendations presented in this report are OGW's independent views.

2.5. Structure of remaining sections of this report

The remaining sections of this report are structured as follows:

- Section 3 discusses the criteria that we have used to assess the likely efficacy of changes to the Code;
- Section 4 outlines our understanding of the changes to the regulatory framework that impact upon investments in grid-side batteries;
- Section 5 discusses how these key changes compare with what happens in the NEM;
- Section 6 discusses the implications for efficient investment in grid-side batteries;
- Section 7 outlines the options for mitigating the impact that the Code might have on efficiency; and
- Section 8 outlines our key conclusions.

3. Criteria used to assess the likely efficacy of changes to the Code

3.1. Objective of this section

The objective of this section of the report is to:

- Outline the criteria that we have used to assess the likely efficacy of changes to the Code, which, in this case, is the 'Code objective'; and
- Describe how we have interpreted that objective.

3.2. Code objective

The objective of the Code ("Code objective") is to:

promote efficient investment in, and efficient operation and use of, services of networks in Western Australia for the long-term interests of consumers in relation to:

(a) price, quality, safety, reliability and security of supply of electricity;

(b) the safety, reliability and security of covered networks; and

(c) the environmental consequences of energy supply and consumption, including reducing greenhouse gas emissions, considering land use and biodiversity impacts, and encouraging energy efficiency and demand management.

{Note: Consumers in the context of the Code objective has the meaning in this Code being "a person who consumes electricity".}

The importance of the Code objective is that it defines the criteria that should be applied by (a) Western Power in making decisions regarding capital investment and system operation and (b) the ERA in assessing Western Power's capital investment proposals.

3.3. How we interpret the Code

The Code objective essentially mirrors the National Electricity Objective (NEO). As the AEMC has previously stated[3]:

"The NEO is an economic concept and is intended to be interpreted as promoting efficiency in the long-term interests of consumers"

The AEMC goes onto state that in all of its rule changes and reviews, its analysis is centred on the concept of efficiency and that efficiency has "*three different elements and each project may emphasise a different one, there may also be trade-offs between these different elements of efficiency*[4]". These three limbs, and how we interpret them are:

- Productive efficiency ('promote efficient investment in'): The least-cost mix of capital and labour should be used to deliver the outputs that customers are willing to pay for.
- Allocative Efficiency ('promote….efficient use of'): Resources should be allocated to their highest value use. A cornerstone of this is that prices for services reflect the opportunity cost to society of making those services available to them.

3 AEMC, *Applying the energy objectives - A guide for stakeholders*, 1 December, 2016, page 3

4 Ibid, page 11

- Dynamic Efficiency (‘for the long term interests of consumers’): Electricity businesses should be incentivised to make efficiency gains over time, and improve performance where benefits exceed costs.

In addition, it is worth noting that item (c) above adds a relatively broadly defined consideration of the ‘environmental consequences of energy supply and consumption’ as an objective of the Code. There is nothing similar to this in the NEO.

3.4. Conceptual framework used to formulate recommendation in this report

In the context of investments in grid-side batteries, we believe the achievement of the Code objective requires three key criteria to be satisfied. These are:

- The regulatory framework should not skew WP’s incentive to invest in (or not invest in, as the case may be) grid-side batteries, if they form the least-cost means of balancing supply and demand for electricity services in the long-term (productive efficiency);
- The regulatory framework should not (artificially) incentivise WP to favour one procurement option over another (e.g., capex over opex; in-source over out-source; one technology over another), potentially leading to less efficient grid-side battery providers being able to obtain market share over more efficient grid-side battery providers, affecting long term efficiency (dynamic efficiency); and
- The regulatory framework should incentivise the owner of an in-situ grid-side battery to maximise the efficiency benefits stemming from its use, having regard to the benefits to the regulated network business and the benefits accruing to competitive markets (i.e., allocative efficiency).

In short, the regulatory framework should encourage productive, allocative and dynamic efficiency in both the market for regulated network services, as well as the market for other services that can be provided by grid-side batteries. Arrangements that foster these outcomes will be consistent with promoting the achievement of the Code.

4. Our understanding of the changes to the regulatory framework that impact investments in grid-side batteries

Our understanding of the existing Code, and changes to the regulatory framework that impact investments in grid-side batteries includes that:

- Changes were made to the Electricity Industry Act 2004 (Act) to explicitly allow WP to deploy distribution-connected storage devices in the SWIS
- Changes were made to the Energy Networks Access Code (2004) to, amongst other things:
  - Increase information provision/transparency regarding the network conditions that could potentially be met through the deployment of grid-side battery storage
  - Reduce administrative costs and asymmetric information related to grid-side battery opportunities
  - Provide for the sharing of any revenue generated from the use of what are termed multi-function assets (e.g., grid-side battery storage) to provide services into unregulated markets, with its regulated customers.
- Existing requirements of the Code appear to allow WP to roll into its capital base, 'new facilities' that are deemed to provide a 'net benefit'.

4.1. Objective of this section

The objective of this section of the report is to outline our:

- Understanding of the changes that have been made to the Electricity Industry Act 2004 (Act), in the context of grid-side batteries;
- Understanding of the key changes to the Code;
- Interpretation of the existing aspects of the Code that relate to the recovery of investments in grid-side batteries; and
- Interpretation of what the changes mean in practice, in the context of the provision and operation of grid-side batteries.

4.2. Changes to the Electricity Industry Act 2004 (Act)

Section 3 of the Explanatory Memorandum Electricity Amendment Bill 2019 provides an overview of the standalone power system (SPS) and electricity storage reforms, the latter of which is most pertinent for this project.

Of particular note, on page 21, it states that[5]:

The Bill also introduces amendments to the Act to facilitate deployment of distribution connected storage devices in the SWIS. The objective of this amendment is similar to those relating to SPS, that is, to ensure that Western Power may provide storage devices deployed within its distribution network, and that the costs of those assets, or a portion of them, are (subject to approval by the ERA in the usual way) able to be recovered through regulated network tariffs under the ENAC.

5 Electricity Industry Amendment Bill 2019, *Explanatory Memorandum*, page 21

In discussing Western Power's participation in these new markets, the Explanatory Memorandum states that[6]:

*The ENAC is intended to set clear boundaries around when Western Power may provide SPS and provide regulated network services using distribution connected storage devices. The **intention is to enable Western Power to operate its existing business efficiently** and with a **view to providing least cost network services**. The intention is **not to create new lines of business for Western Power to compete with private sector SPS and storage providers**…..*

To this end, new section 105(1)(cb) will insert a power for the ENAC to manage Western Power's (and, if necessary, Horizon Power's) use of SPS and storage and their participation in these new energy markets…

*Importantly, the Government's policy is that Western Power should be enabled and permitted to deploy SPS and storage in **response to an identified network need of its primary network business**, to reduce network costs and improve the security and reliability of electricity supply to consumers. **The Government does not intend that Western Power will look to develop new lines of business in the provision of SPS and storage more generally.** It is intended that ENAC provisions made under this new head of power will include, but not necessarily be limited to the following.*

*a) Restricting provision of storage works to distribution connected storage. The Government **does not intend to enable Western Power to deploy transmission connected storage** (grid scale storage) as part of its regulated covered network, such that its costs could be recovered through regulated network tariffs.*

*b) Preventing Western Power from using storage works for other purposes unrelated to the primary purpose of serving a network need. The **Government does not intend for Western Power to use storage works for the purposes of participating in the WEM** (including in respect of the provision of essential system services or providing retail energy services to customers).*

If Western Power incurs prudent and efficient costs of storage works, but under the ENAC, the ERA will not permit it to recover some part of those costs through regulated tariffs, then it is intended that, without relaxing the policy position described in the previous paragraph, the ENAC will permit Western Power an opportunity to earn a return on that unrecovered investment. This could take the form of leasing the capacity of the distribution connected storage works to retailers or others for the purposes of those other persons providing services to retail customers or participating in the WEM.

It goes on to say that[7]:

These SPS and storage works amendments were primarily developed to enable Western Power to consider and use these technologies as a solution for identified network needs.

*Under amendments to be made to the ENAC, the intent is for Western Power to be required to develop a business case for deployment of SPS and storage works for submission to the ERA, as part of the access arrangement revision process. The business case would address available alternatives, **including procurement of an SPS or storage works solution to an identified network need from a third party as an operational rather than capital expense.** The provision of SPS or storage works by Western Power itself would not be a forgone conclusion but would depend on the business case.*

It later states on page 28 that[8]:

*The Government does not propose to empower Western Power to engage in the full range of storage activities. Provisions included in the ENAC under new section 105(1)(cb) will be used to **limit Western Power's use of storage works to those connected to one of its distribution systems, and only as an adjunct to its traditional poles and wires business.***

6 Ibid, pages 21 and 22

7 Ibid, page 22

8 Ibid, page 28

Finally, on page 30 it states that[9]:

The expression "as an adjunct", in this context, is intended to make it clear that SPS and storage works are not network infrastructure facilities in or of themselves. It is their use in supplementing or enhancing a conventional poles and wires network and, by extension, the services that it provides, that allows them to be included within the scope of network infrastructure facilities.

…

It is also intended to serve as a marker that the deployment of these technologies by the NSP of a covered network like Western Power is intended to take place as a response to an identified network need. That is, as what is sometimes described as an alternative solution to a network issue. It may also operate to effectively limit or prevent the potential misclassification of power stations built to serve large isolated customers (for example mining loads) as SPS. See also the explanation of new section 105(1)(ca) in section 6.2.5 of this Memorandum.

4.3. Key changes to the Code

The following table summarises the key changes to the Code.

Table 1: Key changes to the Code

Component of Code	Summary of requirement
Network Opportunity Map – s6A.1 and s6A.2	Western Power (WP) must publish a detailed set of network information which identifies, for example, where network issues are, the timeframes that relate to when these issues need to be addressed, the annual deferred value for augmentations for the next 5 years, and service(s) required
Alternative Options Strategy (AOS) - s6A.3 – s6A.5	WP must set out in an AOS, their strategy for: (a) engaging with providers of alternative options; and (b) considering alternative options. Amongst other things, it must include a Vendor register; it requires WP to engage with providers of alternative options and consider alternative options for addressing transmission and distribution system constraints in accordance with its alternative options strategy; it must include an array of information that is designed to outline how WP will deal with the Alternative Options provider (e.g., "*an outline of the principles that the service provider considers in developing the payment levels for alternative options*"). It also requires that WP must: "*negotiate in good faith with a provider of alternative options regarding the terms for an alternative option service contract based on the model alternative option service contract*".
Alternative Options Service Contract (AOSC) – s6A.7 - 10	The AOSC is to set out standard T&Cs that will be adopted with a third party who is engaged to provide an alternative option to alleviate the identified network needs. The ERA has an approval role in relation to the AOSC.
Net-benefit valuation guidelines	The Authority must make and publish guidelines that provide guidance as to acceptable methodologies for valuing net benefits by a service provider, which methodologies must include, but are not limited to, for the SWIS, consideration of changes in costs for participants in the Wholesale Electricity Market. More broadly, the changes are designed to ensure that any assessment of competing options should consider the overall net benefits for end-use customers, not just the WP network (e.g., account for market costs including those in the wholesale market that can be attributed to the network operator).

9 Ibid, page 30

	Energy Policy WA has stated in a public forum that they believe that this will facilitate greater use of DER, where this is efficient.
DM Innovation allowance (DMIA)	The intent is to provide ex ante funding for WP to undertake small-scale research and development initiatives that constitute "*innovative solutions that may deliver lower cost outcomes for customers*". This was felt to be needed in light of there being no or only minimal incentive under the existing regulatory framework for WP to conduct research and development on network solutions that are not as yet commercially viable. The amount of the funding and the guidelines regarding how it is to be used and reported on are to be determined by the ERA.
'Multi-function assets'	Western Power must develop a multi-function asset policy. It must be consistent with any guidelines developed by the ERA, including the method to determine 'net incremental revenue', which is defined in the Code as "*the revenue from all charges received by a service provider in excess of the revenue it would receive if the asset only provided covered services, for a pricing year*". The Code requires that if an asset is used to provide services other than covered services, the ERA must reduce WP's target revenue for a pricing year within that access arrangement period by an amount equal to 30% of the net incremental revenue. It applies a materiality threshold, being "*if the net incremental revenue derived from the use of all multi-function assets in a pricing year is greater than $1 million (CPI adjusted)*". The ERA "*may make and publish guidelines setting out the approach the Authority proposes to take in applying the multi-function asset principles*", which include, but are not limited to: (a) the service provider should be encouraged to use assets that provide covered services for the provision of other kinds of services where that use is efficient and does not materially prejudice the provision of covered services;….. (e) any reduction effected under section 6.84 should be compatible with other incentives provided under this Code.

4.4. Our interpretation of the existing Code

Our interpretation of the existing Code is that it appeared to:

- Require WP to consider the full suite of benefits across the entire electricity value chain when determining what investments it proposes to make under the New Facilities Investment Test (see definition of 'Net Benefit' in the Code and the New Facilities Investment Test - below), and
- That subject to some constraints, section 6.52 (b)(ii), which relates to the 'New Facilities Investment Test', allows WP to recover those costs from customers through higher reference tariffs if the new facility provides a net benefit in the covered network over a reasonable period of time (see '6.52(b)(ii)).

4.5. Our interpretation of what the changes mean in practice

In practice, the changes, when combined with the existing provisions of the Code, appear to:

- **Increase the transparency of WP's planning and its future requirements:** Changes such as the Network Opportunity Map, Alternative Options Strategy and Alternative Options Service Contract (AOSC) all appear to be designed to increase the transparency around WP's future augmentation requirements. This, in theory, should increase the level of transparency flowing through to 3rd party providers of alternative options, and hence increase the opportunity for them to be actively involved in that market, although it is noted that this information isn't supplied until later in the year, allowing WP to better access that market in the short term, potentially crowding out otherwise more efficient providers.

- **Open up opportunities for WP to use grid-side batteries to provide services to the competitive market:** Whilst the Government's policy is that WP should be enabled and permitted to deploy storage in response to an identified network need, and that its stated intention is not to allow WP to develop new lines of business:
  - WP can provide some services directly to AEMO via bilateral contracts, for example WP is allowed to provide ancillary services under the Electricity Corporations Act[10];
  - WP can lease the battery (or rights to the battery under certain circumstances) to a third party to provide services directly into a specified energy market (for which they, and not WP, are registered to provide services), and by doing so, WP can monetise the economic benefit the battery provides via a lease payment/arrangement with the third-party intermediary.
- **Allow WP to fully recover the costs of grid-side battery storage systems – assuming there are "net benefits" – from regulated tariffs, with any revenue earned from the provision of unregulated services partially (30%) shared with customers.**[11] Our interpretation of the Code is that it:
  - Allows the full capital cost to be rolled into the capital base if it passes the New Facilities Investment Test (NFIT)[12];
  - That this expenditure will flow through to "higher reference tariffs" (as opposed to only the (efficient) costs related to the network portion being rolled in); and
  - Because the full cost of the asset is already in the capital base (not just the portion of the asset that relates to the provision of network services), as a minimum, WP will recover the efficient costs of building a battery that provides 'net benefits', and if the battery is able to be used to sell services into competitive markets, it will retain:
    - 100% of the net incremental revenue obtained from all such non-network applications in aggregate, up to a materiality threshold of $1m for the year (underpinned by the new additions to the Code that relate to multi-function assets), and
    - 70% of any net incremental revenue that exceeds the materiality threshold, or
  - The net incremental revenue could be generated via:
    - Payments for the ancillary services that WP can provide via a grid-side battery (as these are a function that WP is able to provide); and
    - Lease payments (or some other payment) from third party intermediaries for the use of the battery to enable them to provide services into the WEM (that they are able to provide, but which WP is unable to provide under the Electricity Corporations Act 2005).

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10 s41(e) of the Electricity Corporations Act 2005 states that this is a Principal Function of Electricity Network Corporations. However, the approach the ERA will take in relation to the application of NFIT is yet to be published.

11 It should be noted that the detailed operation of the battery as a multi-function asset is still subject to the ERA's (a) publication and approval of a multi-function asset policy under AA5, and (b) publication of the multi-function asset guideline.

12 For the avoidance of doubt, where the net benefits do not cover the full cost of the battery, then only the quantum of the net benefits would be able to be rolled into the capital base. The residual, unrecoverable amount, would be treated as a speculative investment, with this being a defined term in the Code – see 6.58

- **The Access Code precludes any non-capital costs not associated with the efficient provision of *covered services* from being recovered from reference tariffs**[13]: If a third party were to develop a grid-side battery that provided "net benefits", that party would be eligible to receive a payment from WP for the value of the network support services that it provides WP (with these being used to provide *covered services*), not an amount that equates to the "net benefits" of the grid-side battery.

4.6. Case study demonstrating our understanding of how the Code would operate in practice

To elaborate on the above interpretation, consider the following hypothetical case study:

- Western Power has three options to alleviate a network constraint: (a) a grid-side battery, (b) demand-side management network support; and (c) network augmentation. All options provide exactly the same level of service *to the network business* (reflecting their equivalent ability to alleviate a reliability issue)
- However, the options have different: (a) costs; and (b) 'net benefits', as defined in the Code, because of their ability to provide services to other (non-network) parts of the electricity value chain; and
- Option (c), network augmentation, is the lowest cost option, while option (a) is the option that produces the highest overall economic benefit (being 'net benefits').

Table 2 below provides the salient characteristics of each of the three options.

Table 2: Case study highlighting financial flows stemming from the adoption of different options

Parameter	(A) Grid-side battery	(B) Network Support	(C) Network Augmentation
Level of Service to the Network	1MVA network support	1MVA network support	1MVA network support
Annualised Cost (A)	$1m	$900k	$799k
Economic benefit to network business' customers via increased reliability) (B)	$800k	$800k	$800k
Additional (non-network) benefits (e.g., ancillary services) (C)	$250k[14]	$0k	$0k
Net (economic) benefit = (B)+(C)-(A)	$50k	($100k)	$1k
Ranking of option	1	3	2

Our understanding is that the Code is (rightfully) designed in a way to incentivise WP to invest in the grid-side battery in this circumstance, as it is the most efficient investment, having regard to the benefits accruing to the entire electricity value chain – not just the network portion of the value chain.

13 For example, in the Energy Transformation Taskforce, *Energy Transformation Strategy: Proposed Changes to the Electricity Networks Access Code,* Consultation Paper, May 2020, page 21, it is states that (the then current) "*Access Code precludes any non-capital costs not associated with the efficient provision of covered services from being recovered from reference tariffs*" – none of the changes to the access Code appear to change this interpretation of the Code.

14 In reality, the contribution of non-network benefits to the overall business case is likely to be much greater than this. Appendix A provides more detail on the likely benefits accruing to a grid-side battery in WA.

It is also our understanding that in this circumstance, given that the gross benefits exceed the costs (i.e., there is a positive net benefit), the entire cost of the battery would be able to be rolled into the capital base, and recovered via the regulated charges WP proposes. In simple terms, WP's target revenue would be $1m higher pa than under the 'do nothing' case, as a result of rolling in the full cost of the battery, and $201k higher pa than under the network augmentation case.

If, subsequent to the investment in the grid-side battery, WP achieved the additional estimated benefits of $250k that it had originally forecast as accruing to other parts of the electricity value chain (e.g., by selling ancillary services or leasing out the use of the battery to third parties for their use), the overall revenue that WP would generate from the battery would be either:

- $1m plus $250k = $1.25m per annum, if the $1m materiality threshold had not been reached; or
- $1m plus (70%[15] * $250k) = $1.175m if the $1m materiality threshold was reached[16].

In contrast, if a third party were to make the same investment in exactly the same battery at exactly the same upfront capital cost, delivering exactly the same benefits to the network and other parts of the electricity value chain, and assuming it had exactly the same WACC as WP, the potential financial flows are materially less than those accruing to WP, at $1.049m, based on receiving an:

- Annual payment from WP for the network support provided by the battery = $799k[17]; and
- Annual benefit from providing services into the competitive market = $250k.

For the sake of the argument, let's assume that the forecast benefits to other parts of the electricity industry value chain did not eventuate to the extent that were forecast when the battery was installed, due to an unforeseen increase in the supply of those services by other market players (e.g., thus diminishing the economic value of the benefits provided by the battery into those other markets). For simplicity, lets assumed the actual economic benefit (and hence revenues) are 50% of those forecast, at $125k per annum, for the life of the battery. In this situation, the overall revenue that WP would generate from the battery would still cover its underlying cost of owning, operating and maintaining the grid-side battery ($1m), as it would be either:

- $1m plus $125k = $1.125m per annum, if the $1m materiality threshold was not reached; or
- $1m plus (70%[18] * $125k) = $1.0875m if the $1m materiality threshold was reached.

15 For the purposes of this simplified analysis, we assumed that there are no incremental costs associated with providing services to competitive markets.

16 It should also be noted that WP would seek to maximise its leasing revenue, thereby reducing the margins available to parties in the competitive market from the use of the asset.

17 As stated earlier, the *Energy Transformation Strategy: Proposed Changes to the Electricity Networks Access Code, Consultation Paper,* May 2020, page 21 states that (the then current) "*Access Code precludes any non-capital costs not associated with the efficient provision of covered services from being recovered from reference tariffs*" - none of the changes to the access Code appear to change this interpretation of the Code, hence it is our assumption that non-capital costs are not able to compensate a third party provider for the benefits that accrue to non-network parts of the electricity value chain.

18 For the purposes of this simplified analysis, we assumed that there are no incremental costs associated with providing services to competitive markets.

By contrast, if a third party made exactly the same investment, and suffered exactly the same (reduced) level of revenue for non-network services, then its revenues would be $0.924m, lower than the underlying economic cost of owning, operating and maintaining the battery, based on receiving an:

- Annual payment from WP for the network support provided by the battery = $799k; and
- Annual benefit from providing services into the competitive market = $125k.

5. How these key changes compare with what happens in the NEM

5.1. Objective of this section

The objective of this section is to:

- Outline our understanding of how grid-connected batteries are treated in the NEM; and
- Discuss whether the NEM Shared Asset Guideline is used to incentivise efficient investment in use of 'multi-function' assets in the NEM, and if not, why not.

5.2. How grid-connected batteries are treated in the NEM

In the context of a grid-connected battery, it is our understanding that:

- If a battery has been installed by a DNSP to provide grid support, and if the DNSP uses the battery only for network purposes (i.e. to relieve network congestion), then the battery is an input to the provision of a 'distribution service', as defined under the Rules, and hence it would be rolled into the Regulatory Asset Base (RAB)
- If the DNSP trades energy from the battery into the wholesale market – or, if they lease portions of the battery to others to do the same - it is our understanding that this would not be a distribution service, and hence no part of the battery would be able to be rolled into the RAB
- That said, it is a slightly grey area as the DNSP may be able to "lease" land (e.g., at sub stations) to say a retailer so that the retailer could site a battery there, and the unregulated revenue generated from the lease payment would be shared with the DNSP's regulated customers via the Shared Asset Guideline (as the land would be already included in the DNSP's RAB)
- However, it is our understanding that the Shared Asset Guideline would not apply to the leasing of parts of a <u>new</u> battery to a retailer or for the network business to own that battery and provide services into the competitive market; it is our understanding that the Shared Asset Guideline is designed to encourage DNSPs to use <u>existing</u> underutilised regulated assets for the benefit of customers; not as a way of correctly allocating or justifying the costs of new assets that might straddle the reg/un regulated space.

Therefore, in the NEM, a DNSP's ring-fenced business would need to own and operate the battery, and, to the extent that the battery is also used to provide services back into the regulated network business to provide regulated 'distribution services', the DNSP could recover the efficient costs of procuring those services from its ring-fenced entity (subject to those costs meeting the overarching Rules). However, the DNSP may apply to the AER to waive the ring-fencing arrangements/requirements.

This is clearly very different to what is being proposed in the WEM, where the regulated business can own and operate a battery which can then be used to provide services to competitive markets.

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5.3. Is the Shared Asset Guideline used to incentivise efficient investment in use of 'multi-function' assets?

In an example that relates to distributors offering services into emerging markets for FCAS using their network control systems, which is contained in the AER's "Explanatory statement, Draft electricity distribution service classification guideline, page 23, June 2018", the AER states the following[19]:

SAG is designed to encourage DNSPs to use underutilised regulated assets for the benefit of customers. SAG is not intended to reflect the correct allocation of costs and as a result, the proposed use of the SAG would result in a cross subsidy. This is because the revenue sharing arrangements in the SAG are not intended to be an alternative cost allocation method.

Use of the SAG is restricted to circumstances in which the use of assets in the RAB will not materially prejudice the use of the asset for standard control purposes. DNSPs would need to ensure that use of regulated assets to provide FCAS does not affect the provision of standard control services.

The SAG cannot be used in a forward looking manner. That is, when a DNSP invests in new control systems, the use of these systems must be factored into allocation of costs. This means that a future investment in its control system should reflect the expected future use of the assets for network system control and FCAS service delivery. SAG cannot be used for future investments

There is a risk that in providing FCAS services, DNSPs may be encouraged to over invest in control systems and attribute this to meeting network requirements

Given the above, it could be difficult to avoid cross subsidies becoming embedded in the provision of FCAS services. This would be detrimental to the development of the markets and is prohibited under the Ring-fencing Guideline.

19 AER, "*Explanatory statement, Draft electricity distribution service classification guideline*", page 23, June 2018

6. Implications for efficient investment in grid-side batteries

6.1. Objective of this section

The objective of this section of the report is to:

- Outline the theoretical issues associated with allowing Western Power to provide both regulated and unregulated services; and
- Describe how several specific Code changes are likely to impact Western Power's incentive to provide efficient services.

6.2. Theoretical issues

The following sections highlight potential theoretical issues associated with the arrangements that are being proposed in WA.

6.2.1. Inconsistent with Hilmer Reforms

As a general construct, the approach being adopted in WA ascribes "regulated status" to a service that is otherwise contestable and in theory, should not be considered to be a monopoly service (and hence, part of the defined regulated service/s provided by a network business).

This conflicts with the original Hilmer Reforms that underpin the regulatory regimes that are in place today – that services that can only be provided efficiently by a monopoly provider must be separated from those services that can be provided through markets.

This is the underlying rationale for the approach that is adopted in the NEM, whereby, if a DNSP is seeking to operate a battery in a manner that interacts with competitive parts of the electricity market, then that asset cannot be rolled into the RAB, rather, the DNSP can only purchase services from the battery (if that is deemed to be efficient, in the context of providing regulated electricity network services).

6.2.2. Incentive for Western Power to make inefficient investments

If our interpretation of the Access Code, as illustrated in the case study presented earlier, is correct, then it would appear inevitable that the proposed approach would increase Western Power's incentive to seek to justify making investments in grid-side storage solutions, as compared to other assets that could provide equivalent network support services, even where grid-side batteries may not be the most efficient solution.

If WP can make 'excess profits', due to the way the regulatory framework accounts for this unregulated revenue (which it appears is a likely outcome, based on our understanding of the code and as demonstrated by our earlier case study), then, everything else being equal, this will incentivise Western Power to over-invest in grid side battery services of their own accord, at the expense of procuring such services from other market participants (because the opportunity cost to WP of procuring the service provided by the battery from the market rather than investing in the battery itself is that it gives up the possibility of earning excess returns, over and above the actual economic cost of the investment), or from adopting alternative options for efficiently balancing supply and demand for its network services.

6.3. Impact on competition and in turn dynamic efficiency

More broadly, if our understanding of the Code and how it would be practically applied is correct, the approach could have a deleterious effect on competition for the provision of both network support services and services to other portions of the value chain. This is simply because the expected financial returns that would accrue to WP, as compared to third parties, for the provision of exactly the same asset at exactly the same costs, creates an uneven playing field. Such circumstances are likely to have the effect of crowding out parties who may otherwise have competed for the provision of those services, impacting the market for those services in the medium and the long term, and negatively affecting customer outcomes. In its Access Code submission ('*Proposed Amendments to the Electricity Networks Access Code 2004*'), AEMO raised the issue of the arrangements crowding out third-party providers when it suggested the following change to the drafting of the Code:

'economically prudent and efficient', as it pertains to Western Power's business case, and the ERA's assessment of that business case, [should] includes consideration of the economic costs of crowding out third-party provision of storage works (including equipment for SPS), and the actual or potential future impact of the business case on the competitive provision of the service by third-party providers.

6.3.1. Distinction between asset and service

As a general observation, the proposed approach blurs the distinction between an asset with the service(s) it can provide. Assets are not generally the subject of economic regulation (though they may be subject to technical standards, licensing requirements and similar measures). By contrast, the provision of services – and particularly services provided by a regulated monopoly – are generally subject to economic regulation.

6.4. Specific issues that relate to the changes to the Code and how they impact on WP incentives to engage efficient third-party providers of Alternative Options

6.4.1. Sharing of net incremental revenues generated from multi-function assets

We note that unlike the AER's shared asset guideline - which the multi-function asset provisions (particularly the "sharing" of unregulated revenues) appear to be modelled upon[20] - the Code appears to utilise the revenue sharing provisions as a means of allocating the costs of new assets that provide both regulated and unregulated services. As the AER noted in one of its published documents[21]:

"SAG [shared asset guideline] is not intended to reflect the correct allocation of costs and as a result, the proposed use of the SAG would result in a cross subsidy. This because the revenue sharing arrangements in the SAG are not intended to be an alternative cost allocation method".

The AER then notes that if the revenue sharing provisions of the SAG were relied upon, then there would be[22]:

"A risk that in providing [unregulated] FCAS services, DNSPs may be encouraged to over invest in control systems and attribute this to meeting network requirements"

20 We note that in our discussions with EPWA, they acknowledged that the design of the MFA was modelled on the approach that was adopted in the NEM in relation to the Shared Asset Guidelines.

21 AER, "*Explanatory statement, Draft electricity distribution service classification guideline*", June 2018

22 For the avoidance of doubt, the same case can be made about any unregulated service, not just FCAS.

Another way of framing this is that the sharing of revenue under the SAG is predominately done to ensure that there is an equitable sharing of costs (i.e., to benefit the customers who have funded the asset that is used to derive additional, unregulated, revenue), and only where it will not influence the particular technology or technical solution that is adopted. A good example of this is a business' investment in poles or wires – whether a portion of unregulated revenue is shared or not will not (and should not) influence whether or not the network business makes the initial investment in the poles and wires in the first place (or the 'type of pole/wire').

To the extent that this is not the case (that is, the asset is not something that the network would have invested in anyway even in the absence of unregulated revenue), and assets are truly 'multi-function', then the sharing or revenue should not be used; it is not "an alternative cost allocation method".

6.4.2. Impact on the allocation of risk allocation and hence cost of capital

If our interpretation of the Access Code, as illustrated in our earlier case study, is correct, it appears that the minimum revenue that WP would recover, absent any ex post review[23], from an approved investment in a grid-side battery, is 100% of the asset's economic cost (even if accrues no 'net benefit' in actuality). As outlined earlier, this creates an uneven playing field, whereby:

- WP's exposure to future unregulated revenues is asymmetric - it will always be able to recover the costs of the asset from their regulated customers, and any unregulated revenue is 'upside'; whereas
- A third party provider proposing the same asset at the same capital cost, faces significantly more uncertainty and risk as to whether it will recover the economic costs of the battery investment, as it relies upon an uncertain stream of revenue from selling services into a competitive market (assuming WP only contracts with them for the provision of network services – e.g., annual deferral value).

A competitive firm (who would bear this risk) would therefore presumably apply a higher WACC on a grid-side battery project, relative to WP, even if there was in fact no difference in the actual financing costs. Perversely, this premium would be driven by the regulatory arrangements and how costs are recovered, and impact how upside revenue is treated.

6.4.3. Materiality threshold

As stated earlier, the Code stipulates that a "*multi-function asset revenue reduction should be applied where the use of the asset other than for covered services is material", and "the use of a multi-function asset other than for covered services is material if the net incremental revenue derived from the use of all multi-function assets in a pricing year is greater than $1 million (CPI adjusted)*".

23 In our discussions with EPWA, there appeared to be a significant amount of reliance being placed on the ERA ability and willingness to undertake ex post reviews and claw back provisions to preclude excess expenditure on such an asset. The grounds for such a clawback are not entirely specified in the Code, but could include the asset not actually producing the forecast net benefits that were assumed at the time the investment was proposed. It is our view that this will not mitigate the competitive advantage discussed above or the consequent impact on the competitive market for the provision of batteries or battery services. In the first instance, it assumes regulatory processes that are untested and as yet not entirely defined. For another, for this to fully mitigate the competitive consequences of the new arrangements introduced in the Code, the possibility of a clawback would need to be sufficient to dissuade WP from making the investment in the future. To the extent that the investment is made, it will have already displaced the potential for the battery to be provided by the competitive market. Any clawback imposed will not change this.

As stated earlier, in practice, this means that WP is able to retain 100% of the net incremental revenue, where the revenue that it generates in total from such multi-function assets is less than $1m in a given year.

This will inevitably exacerbate[24] WP's underlying economic incentive to both:

- Invest in grid-side batteries over other potential options that provide similar services; and
- Engage with the competitive market in a manner that is consistent with what would occur if the 'playing field' was level – in that WP retains 100% of the value of the first $1m of unregulated services it provides, in addition to recovering 100% of the underlying cost of the battery itself, whereas a competitive provider of the same asset would not be faced with anywhere near the same financial incentives (even if the same economic benefits were to be delivered).

6.4.4. Potential for misuse of DMIA funds

The objective of the Demand Management Innovation Allowance (DMIA) mechanism is to "*provide service providers with funding for research and development in demand management projects that have the potential to reduce long term network costs*".

Whilst this is a reasonable objective, the potential problem, depending on how the term "*demand management projects*" is interpreted, is that it could possibly provide a means for WP to develop products and services that could be leveraged off grid-side batteries, which in turn would put the provision of those services by WP in competition *with* products and services that could otherwise be developed by parties operating in the competitive market. Yet:

- For WP, this R&D expenditure is a "riskless" exercise, in that it is fully recoverable from regulated customers under the DMIA, hence its shareholder is not actually putting any of its funds 'at risk'; compared with
- Third party providers operating in the competitive market, whose investment in the same type of R&D would involve them putting their shareholders' funds 'at risk'.

This situation could lead to competitive market providers who may have otherwise undertaken R&D in order to expand their capabilities to provide demand management services that leverage off grid-side batteries, to be crowded out of the market (i.e., to elect NOT to put their shareholder funds at risk, due to the perceived unequal playing field). Less competition means less innovation, less pressure to innovate, and generally, diminished economic efficiency in the long-term (dynamic efficiency).

6.4.5. Timing, given the 'Clear and Present Challenge' facing the supply chain

EPWA's Distributed Energy Resources Roadmap documents the increase in the installation and electricity production of DER systems and the impact of their as yet almost entirely passive operation on the various portions of the electricity supply chain. Of most pressing concern is the potential that the continued uptake and passive operation of rooftop solar PV could result in daytime demand falling to levels at which there will be significant risk of instability in the SWIS. The Roadmap cites an AEMO forecast that this could occur as early as 2022.

24 We use the term exacerbate, as these incentives are, in our opinion, there, even once the materiality threshold is preached, but they are 'exacerbated' below the threshold.

Actions 5a and 5b of the Distributed Energy Resources Roadmap relate to the deployment of grid-side batteries which can be used to better control the impact of rooftop PV on the supply system above the LV network[25].

- Step 5a specifies the deployment of community batteries by WP in 10 network locations by December 2020[26].
- Step 5b requires WP to develop, by October 2020, a plan for installing batteries to provide the additional storage services it believes will be needed through 2024 in the event that those services do not emerge from the market[27].

However, while WP will be required to publish a Network Opportunity Map by October of every year starting in 2021, the needs through 2024, which will have been identified by WP by October 2020, are not required to be published until a full year later. This has the potential to preclude the private sector out of these opportunities.

To the extent that the underlying rationale for these changes is that the network is facing a clear and imminent "challenge" from the amount of electricity being exported to the grid in an uncontrolled manner, and there is an expectation that battery storage services that could address these issues can be provided by the competitive market, it is not clear why the needs identified by WP through 2024 should not be made public, even if not in the form contemplated to be used in a fully compliant Network Opportunity Map. Not doing so limits the competitive market from responding to these needs.

The establishment of priority projects in the Code further exacerbates this problem as these projects are not subject to any requirement for exposure to the private market or even to post prudency review by the regulator.

It is not clear why the priority project provisions are not time limited. It is also not clear why clearly defined regulatory processes and the use of the new arrangements, including the Network Opportunity Maps, Alternative Options Strategy and Alternative Options Services Contract should not be able to be relied upon. More specifically, we do not see why the first regulatory period (or some shorter period) would not be sufficient for identifying those network areas in which rectification is required in the short term, after which it should be possible to rely on the arrangements mentioned above to allow more competition in the provision of grid-scale batteries and the services they can provide to the various parts of the electricity supply chain.

In our view, the lack of a time limit on the priority project provisions and the delay in allowing the competitive market to respond to identified needs appears to reflect a preference for the provision of these services by a regulated monopoly. We agree that these services are of critical importance but would suggest that the proper role for WP is as the provider of last resort of these services, in which role they would advertise the need but have plans for implementation only in the event that the competitive market was unable or unwilling to provide services to meet the identified need.

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25 Steps 1 through 4 address technical improvements in inverter technology.

26 It is our understanding that 12 'Powerbank' batteries have been deployed at the time this report was written, though the exact status and level of their use was not known.

27 WP advertised the need for demand control services in four zone substation areas in December 2020. Responses were required by 1 January 2021 and the required distributed demand control services were required to be operational by 1 October 2021 (see https://www.westernpower.com.au/media/4661/roi-advert-demand-control-final-123.pdf..

7. Options for mitigating the impact on efficiency

7.1. Objective of this section

The objective of this section is to:

- Outline changes that could be made in the long-term to the regulatory framework; and
- Discuss changes that could be adopted in the short-term to facilitate efficient investment in grid-side batteries.

7.2. Changes that could be made in the long-term to the regulatory framework

Notwithstanding the fact that the changes that have been made to the Code are in place and will be implemented, there are a number of things that could be done to improve the regulatory framework in the longer term. Several are described below.

7.2.1. Only provide services through a ring-fenced entity

EPWA has stated[28] that the current regulatory framework allows the ERA to require ring-fencing arrangements to be put in place should they consider that to be necessary. The provision of this decision-making authority is valuable; we assume that it was made a discretionary power rather than being incorporated directly in the regulatory framework because there is no 'evidence' that the changes enacted in the Code will reduce the role of competition in the provision of batteries and/or the services batteries can provide.

As discussed above, except for the need for the provision of such services in emergency situations in the very near term, we think there is ample reason to believe that the very nature of the changes enacted in the Code will in fact result in WP having a competitive advantage with regard to the deployment and ownership of grid-scale batteries.

Rather than requiring the ERA to justify (i.e., compile an evidence base for) a decision to require ring-fencing, EPWA should consider setting a timeframe after which WP will be required to procure non-network services from the market (where the non-network solution is the most efficient means for meeting the network need), including through a ring-fenced subsidiary owned by the Electricity Networks Corporation. Such an arrangement would preserve the opportunity for the competitive market to provide lower cost and innovative solutions, and a WP-related entity that could be expected to ensure that any need for which battery storage services could provide commercially viable solution would be addressed.

This would also make it easier to overcome potential issues such as:

- Site availability, as the availability of and the costs assumed in the provision of space for a grid-side battery deployed as a WP-owned asset would not be discoverable by the competitive market, but would transparent if the provision of the asset and its services were assumed to be provided in the first instance by an external part, including a ring-fenced WP-owned business

28 For the avoidance of doubt, this statement reflects our understanding of EPWA's position (i.e., what it believes the Code allows the ERA to do). However, our reading of the Code, as it relates to the ERA's ability to introduce ring-fencing arrangements for Western Power, is that there may in fact be some limitations in the context of a grid-side battery that is used to provide ancillary services, or which is leased to a third party that provides services into a competitive market.

- Connection requirements, which would not be transparent in the event the asset was be deployed as a WP-owned asset but would need to apply the same requirements to an external party, including a ring-fenced WP-owned business.

Both of these matters represent areas for conflicts of interest to arise in WP's assessment and treatment of options for obtaining services needed for network purposes from external parties as compared to self-provision. This was recognised in submissions in the consultation on the draft changes to the Code, including by the ERA:

Western Power's ownership of batteries could represent a conflict in the same way it would be conflicted by owning generation. The possible conflict in this expansion of Western Power's responsibilities was recently raised in several submissions to EPWA's consultation on proposed changes to the Access Code. Many submissions expressed concern or reservations about Western Power's move to install batteries, including one from the market operator. Western Power is prohibited from owning generation facilities as this would provide an incentive for it to limit competitors' access to the network. For example, Western Power may have an incentive to make it difficult for third parties to invest in batteries that would compete with its own investment in batteries, by setting onerous technical performance standards or unfavourable network tariffs.[29]

7.2.2. Adopting a NEM-style 'shared asset' provision (reducing target revenue by a certain percentage) to only incentivise the efficient use of existing assets.

In the NEM, the shared asset provision is only applicable to existing assets, not potential new assets. This means it only incentivises new or additional uses for assets that have already been deemed to be required and have been determined to be efficient for meeting a network need. The DSNP then shares a portion of the revenue for those new or additional uses with the network's customers.

By contrast, the MFA (particularly in combination with the treatment of net benefits under the NFIT[30]) provides WP with no-risk upside in potentially over-sized grid-scale batteries that provide net market benefits.

7.2.3. Consideration of economic costs of crowding out third-party providers (e.g., impact on dynamic efficiency)

As noted by AEMO in one of its submissions, the consideration of the economic prudence and efficiency of network investments allowed under the new arrangements made available under the Code should consider the longer-term impact they may have on the provision of those services by the competitive market, and therefore the potential reduction in dynamic efficiency.

There would be merit in EPWA undertaking a separate study and consultation on this, potentially in conjunction with consideration of setting a sunset date for the use of priority projects and a requirement for the WP to procure energy storage services (where they constitute the most efficient means for meeting a network need) from the competitive market, including the use of a ring-fenced subsidiary business.

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29 https://www.erawa.com.au/cproot/21468/2/WEM-Report---Final---2020-v4.1-Redacted-further-for-Publication.PDF

30 See the discussion in section 7.2.6 for a discussion of the importance of several aspects of the guidelines to be developed regarding the net benefits test.

7.2.4. Require commercial arrangements with third-party providers to align with risk sharing arrangements faced by Western Power to ensure a level playing field

Another option would be to change the Code so that there is a level playing field, as measured by the financial flows to different parties for the adoption of the same asset delivering the same functionality.

Using our earlier case study as an example, instead of WP only paying a third-party provider of a grid-side battery for the network benefits they provide, WP could be required to pay them for the expected 'net benefits' (as defined in the Code) associated with the provision of the grid-side battery (or the net benefits that they accrue, after allowing for the operation of the 70:30 split of unregulated revenue). Everything else being equal, this would enable third party providers who are more efficient than WP – whether due to their ability to deploy a battery that provides the requisite functionality, more cheaply, or as a result of their ability to extract more economic benefits from the same grid-side battery (e.g., because of the way they operate it) – to effectively compete in the market.

7.2.5. Other marginal refinements to the Code

Reducing the materiality threshold applied

Further consideration should be given to the level of the materiality threshold, given its potential impact on the energy storage market. In particular, consideration could be given to setting it at a level that reflects WP's costs of administering any revenue sharing mechanism (i.e., the costs of adjusting tariffs to reflect the 70:30 split of unregulated revenue, including the costs of preparing the requisite supporting information). This is likely to be considerably lower than the current level of $1m annually.

Increase the percentage passed through

Further consideration could be given to increasing the amount of unregulated revenue generated from multi-function assets that flows through to end customers (via reductions in WP target revenue). As a minimum, a 50:50 split could be adopted, but beyond this, a 30:70 split (in the customers favour) is likely to be even more appropriate. The latter broadly aligns with how efficiency benefits are shared between shareholders and customers (e.g., under efficiency benefit sharing schemes). It would also dampen any incentive WP might have to deploy (inefficient) grid-side batteries, resulting from their ability to financially benefit from the sharing of unregulated revenue.

7.2.6. Changes that could be adopted in the short-term to facilitate efficient investment in grid-side batteries

There are a number of instruments that are yet to be developed whose function is to guide particular aspects of the implementation of the changes that have been made to the Code and the intentions underlying them. In particular, there are a number of Guidelines to be developed by the ERA that will affect the behaviour of WP and its interactions with the market. These include guidelines concerning:

- Net benefits valuation (Clause 6A.6)
- The New Facilities Investment Test (NFIT, Clause 6.52)
- Multi-function Assets (Clause 6.88)
- The Model Alternative Options Services Contract (Clause 6A.8)
- The Demand Management Innovation Allowance (DMIA, Clause 6.32D).

The following paragraphs provide thoughts on specific features that could be put in place in each of those Guidelines that would serve to maintain as much scope as possible for the competitive market and the advantages it can provide in delivering the benefits of the services that energy storage can provide to the various parts of the electricity supply chain.

Net Benefit Valuation Guidelines

The Code (Clause 6A.6) states:

The Authority must make and publish guidelines that provide guidance as to acceptable methodologies for valuing net benefits by a service provider, which methodologies must include, but are not limited to, for the SWIS, consideration of changes in costs for participants in the Wholesale Electricity Market.

There is no reason to believe that WP is expert in the conduct of net benefit analyses or that it has sufficient expertise to assess the value of the various impacts that the services of a grid-side battery can have on the various parts of the electricity value chain. As such, it would be helpful for the ERA Guideline to prescribe the methodology and key inputs to be used by WP in conducting the net benefits of any grid-side battery project it proposes.

The methodological guideline should specify how the test is to be undertaken, the form in which results are to be presented, and the specific areas of benefit to be included as well as how they are to be assessed. This will ensure consistency in the test across projects and that the test is carried out in a way that the ERA feel provides as accurate and meaningful an assessment of the benefits as possible. The guideline should also provide the values to be used for at least the following key inputs and parameters:

- The time horizon for over which the analysis is to be undertaken
- The current and projected value of each benefit to be included in the test
- The discount rate to be used.

More generally, the guidelines should specify that the quantification of net benefits be undertaken using recognised engineering and economic models.

In addition, there would certainly be merit in getting stakeholder input on a draft version of the methodology and the initial input values to be used prior to finalisation of the guideline.

The handling of environmental benefits will be a key issue in the conduct of the net benefits test. Item (c) of the Code Objective essentially states that

efficient investment in, and efficient operation and use of, services provided by means of networks in Western Australia for the long-term interests of consumers [includes] . . . the environmental consequences of energy supply and consumption, including reducing carbon pollution, considering land use and biodiversity impacts, and encouraging energy efficiency and demand management.

To address this aspect of the Code Objective in quantitative terms, the Guideline will need to identify the specific environmental benefits to be assessed, the specific values to be used for each and the drivers/conditions that give rise to them. This is clearly a difficult undertaking and the ERA may need to consider and consult with stakeholders (including EPWA) in whether and if so how the net benefits test can be fashioned to address this aspect of the Code Objective.

Other specific recommendations regarding the specification of the net benefits test include:

- ***Evidence should be provided regarding the plausibility that the net benefits claimed will or are very likely to eventuate***. Given the fact that the net benefits are what in many cases will be the justification for the entire cost of the asset being recovered from network users via the network tariff, it is reasonable to require a robust presentation of the likelihood that those benefits will be delivered. Requiring such documentation will also provide an improved basis on which to assess the outcome in the post prudency review, which should be made a mandatory feature of the regulatory process regarding grid-scale batteries deployed by WP.
- ***Benefits considered under the net benefits test should not include transfer payments*** between producers of electricity, the network owner, network users and/or consumers of electricity; that is, where the benefit to one party is offset by a corresponding and associated cost to another party. To illustrate with a practical example, this principle would mean that a reduction in wholesale electricity price should not be seen as a benefit[31] as it will almost certainly entail some level of transfer between energy producers and energy consumers. Rather the benefit within a reduction in wholesale electricity price should be defined as the reduction in the production costs of wholesale electricity.

New facilities investment test Guideline

The Code states in Clause 6.56 that:

The Authority must make and publish guidelines that provide guidance as to the factors the Authority proposes to consider in making a determination under section 6.52.

Clause 6.52 lays out the conditions under which the NFIT can be met and the cost of the asset can be put in the RAB and recovered through tariffs. In our view, the key clauses regarding the impact of the NFIT on competition are:

- "the new facility provides a net benefit in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs" (Clause 6.52 (b) (ii), or
- "the new facility is in respect of a priority project" (Clause 6.52 (b) (iv).

Our thoughts on the net benefits test were provided above. In relation to the latter clause, it would be useful for the Guideline on the NFIT to include some explanation of (a) whether the category of priority project and the classification of a grid-side battery as a priority project should be phased out at some point and (b) the conditions that would justify those decisions.

Multi-function asset guidelines

The Code states in Clause 6.88 that:

The Authority may make and publish guidelines setting out the approach the Authority proposes to take in applying the multi-function asset principles (which may include a methodology that the Authority proposes to use to determine reductions for the purposes of section 6.84) and must consult the public in accordance with Appendix 7 before making and publishing any multi-function asset guidelines.

In our view, in the approach to be used in calculating net incremental revenue (i.e., the '*methodology that the Authority proposes to use to determine reductions for the purposes of section 6.84*') the costs incurred by WP in obtaining that revenue should be considered at the margin. That is, Western Power should not be allowed to load up its costs with recovery of fixed, sunk or overhead costs, that are not incremental to the decision to use the in situ energy storage device to generate those incremental revenues.

31 Although the *net* impact of any price change on consumer and producer surplus should be considered.

Model Alternative Option Service Contract

The Code in Clause 6A.8 states that:

The Authority must approve a model alternative option service contract if it is reasonably satisfied that it complies with section 6A.7.

6A.9 If the Authority does not approve a model alternative option service contract, the Authority must notify the service provider of the changes required for it to be approved.

6A.10 The Authority may consult the public before making a decision to approve or not approve a model alternative option service contract.

Clause 6A.7 states that alternative option service contract must:

- be reasonable; and
- be sufficiently detailed and complete to enable the *alternative options* provider to understand in advance how the *model alternative option service contract* will be applied; and
- contain provisions that can be utilised to specify the rights and obligations agreed between the *service provider* and the *alternative options* provider in respect to 14 specific areas.

This is a good start but could be improved by the ERA providing some indication of any specific content or rights and responsibilities it would expect the alternative option service contract to contain. It would also be useful to identify any conditions under which this content or the rights and responsibilities of the parties might change in the case of different grid-side battery projects.

Demand Management Innovations Allowance Mechanism Guidelines

In Clause 6.32D the Code states that:

The Authority must make and publish guidelines which must include a demand management innovation allowance mechanism consistent with the demand management innovation allowance objective and the information specified in section 6.32J.

When developing this Guideline, the ERA should make it clear that any expenditure that is directly or indirectly related to the development of products that are likely to otherwise be utilised to provide unregulated services, via the development or utilisation of multi-function assets, will not be considered for funding under the Scheme. The rationale for this is, amongst other things, to better meet the overarching objective of the Code (via reducing the risk that inappropriate funding of R&D will have a chilling effect on investments made by the broader competitive market), and because funding is available from another source (i.e., shareholders), which means it does not comply with the requirement in Clause 6.32G (c) (ii) that the allowance "should only provide funding that is not available from any other source."

8. Conclusions

8.1. Reduced likelihood of achieving the Code objective

As noted in section 3.2, at the highest level, the object of the Code is to:

promote the efficient investment in, and efficient operation and use of, services provided by means of networks in Western Australia for the long-term interests of consumers . . .

Our analysis suggests that the Code is unlikely to achieve this. The key cause of this is the part of the New Facilities Investment Test – specifically Clause 6.52 (b) (ii) – which allows WP to recover the costs of grid-side battery investments based on their *potential* to produce net benefits (potentially including environmental benefits).

This has the potential to:

- Reduce productive efficiency and increase costs to consumers: This is because WP appears to be overly incentivised to make investments in multi-function assets, relative to other types of assets, due to their ability to capture and retain either 100% or 70% of the incremental (unregulated) revenue that can be generated from those assets, on top of recovering 100% of the economic costs of installing those assets in the first place from regulated customers.
- Reduce dynamic efficiency: The financial flows that ensue from the adoption of grid-side batteries appear to differ, depending on whether WP or a third-party provider owns and operates the asset (even for the same asset providing exactly the same economic benefit). This uneven playing field, to the extent that it disadvantages third party competitive providers, will disincentivise those parties (who may have otherwise been interested in investing in grid-side batteries and making their services available to various parts of the electricity supply chain) from competing to provide these service. Less competition means less innovation, less pressure to innovate, and generally, diminished economic efficiency in the long-term (dynamic efficiency).

The temporally unlimited provisions that allow priority project to be undertaken with minimal regulatory scrutiny also contribute to the impacts discussed above.

8.2. Over reliance on ex post regulatory intervention

The Code as amended places a significant amount of reliance on regulatory intervention. This is most apparent in the assumptions that:

- Any over-investment allowed into the RAB under the NFIT (as discussed above) will be identified and corrected by the regulator during any ex post review , and
- The need for and timing of the implementation of ring-fencing should be determined by the regulator.

Generally, regulation seeks to enact policies and principles set by a rule-making body and put in place mechanisms that incentivise the regulated party to reveal its efficient costs of operation. The changes to the Code do not do this.

- Leaving the decision regarding the need for ring-fencing to the regulator – particularly without an explicit instruction and guidance regarding policy expectations and the criteria to be applied – is not an appropriate substitute for the development of rules and regulatory mechanisms that provide clear and commercially viable signals that incentivise behaviour that aligns with policy objectives

- Assuming that capex allowances based on net benefits (that are likely to include factors such as environmental benefits that are very difficult to quantify) will be corrected in post-prudency reviews conducted by the regulator:
  - Puts significant pressure on the regulator
  - Relies on a process that is time-consuming and can be challenged in court, which may induce conservatism in the regulator's decisions
  - Will not be able to correct one of the major shortcomings of the use of the net benefits test in the NFIT, namely its potential to crowd out investment from the competitive market.

8.3. The importance of the implementation Guidelines

The Code specifies several Guidelines that are to be developed by the ERA for implementing the various parts of the Code. Given that the changes to the Code have been approved and the issues described above are unlikely to be corrected through further amendments to the Code (at least for the time being), the details of these Guidelines represent the only way that the shortcomings of the Code can be ameliorated. It is important that this opportunity is used effectively while also reiterating and seeking re-consideration of the larger issues identified in this report with the changes that have been made to the Code.

Appendix A: High-level quantification of benefits provided by a grid-side battery

We were asked by the AEC to undertake a targeted but high-level quantitative analysis, highlighting the potential impacts of the proposed arrangements. This was to include:

- **1A:** Estimating the proportion of revenue generated from 'network' services compared with 'contestable' services in the WA environment[32]
- **1B:** Estimating the proportion of WA's peak demand and FCAS market that could be supplied by grid scale batteries, given assumptions around the size and number of batteries (e.g., high, medium, low take-up)
- **1C:** Using information available from WA to estimate the proportion of the annual grid-scale battery annualised costs that can be met by published network augmentation deferral costs

Results of Task 1A

The results for a notional 5MW/10MWh[33] grid-side battery are summarised in the following table.

Table 3: Estimated proportion of revenue generated from 'network' services compared with 'contestable' services in the WA environment

Revenue Stream	Value	Proportion	Assumptions
Balancing Market	$187,059	26.84%	Price arbitrage based on a daily cycling of the battery, and a 2hr charge and a 2 hr discharge period in response to balancing market prices (CY20 prices). See Figure 1 below which shows the prices in the Balancing Market for CY2020.
Network - Dx	$180,000	25.82%	LRMC of $60/kVA based on other DB's published prices[34], along with a 3-hr discharge cycle to reflect duration of peak periods on peak day (as derived from CY2020 Balancing Market data)
Network - Tx	$45,000	6.46%	LRMC of $15/kVA, based on the average of AEMO's Locational TUoS tariffs applying to the Victorian Transmission Network (which are purported to be reflective of the LRMC), across an assumed 3-hour discharge cycle
Reserve Capacity Mechanism (RCM)	$285,000	40.89%	Assumes that for the purposes of calculating a battery's contribution to the RCM, it is derated to a 4-hr capacity (so 2.5MWh), with this multiplied by the 2021 reserve capacity price of $114k per MW[35].
TOTAL	**$697,059**	**100.00%**	

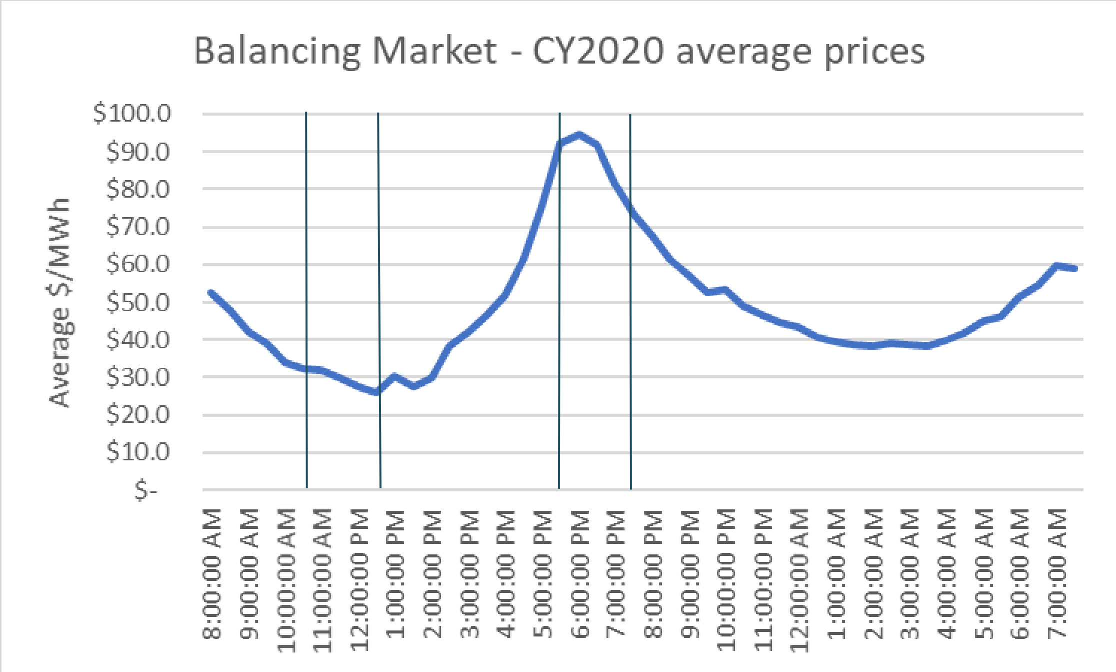
32 In developing this, we flagged the use of relevant WA information where readily available.

33 For the avoidance of doubt, the size has no effect on the proportions, although the relationship between MW and MWh does.

34 For example, see AusGrid's published LRMC model: https://energyconsumersaustralia.worldsecuresystems.com/Report%20community%20battery%20ownership%20models%20Feb2020.pdf
and page 41 of AusNet's published TSS
https://www.ausnetservices.com.au/-/media/Files/AusNet/About-Us/Network-Tariffs/Electricity/Revised-Tariff-Structure-Statement-Compliance-Document--031220---PUBLIC.ashx?la=en.

35 https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/data-wem/market-data-wa [Reserve Capacity Prices]

Figure 1: Average prices (and charge/discharge periods) in the Balancing Market – CY2020



Other key assumptions include:

- Balancing Market: Battery owner/operator would:
  - Preference offering energy from the battery into the Balancing Market over the Short Term Energy Market (STEM) due to the greater flexibility offered from this approach (e.g., it limits the need to enter into a long-term contract), whilst also providing exposure to the greater price volatility that is evidenced[36] in the Balancing Market (which the battery operator is assumed to be able to manage and/or respond to, hence it would be preferred); and
  - Operate the battery on a daily charge/discharge cycle, with charging during low price periods (10.30am to 12.30pm) and discharging during high price periods (5.30pm to 7.30pm), adjusted for a 90% round trip efficiency. Average prices during these periods are based on reported actual prices for the 2020 calendar year (see Figure 1 above).
- Network Capacity Support: Western Power does not appear to have published any recent estimates of its LRMC of supply, hence we have relied on information published by network businesses in the NEM. The support offered by a battery is assumed to be required for a 3-hour period (i.e., to make any material difference to overall peak demand, it needs to operate for this length of time, as this is the general duration of the peak), with this duration based on an assessment of the load profile in the wholesale market. It is assumed, not unreasonably in our opinion, that the battery's ability to offer network support services during peak demand periods does not compromise its ability to offer other services in the Balancing Market and the Reserve Capacity Mechanism (e.g., discharge for network support services will provide energy into the grid, the value of which is able to be monetised via Balancing Market Prices).

36 Based on analysis of 2020CY data.

- Reserve Capacity Mechanism (RCM): The extent to which a new grid-side battery will be able to monetise the capacity benefits it provides to the market (via the RCM) will be a function of (a) the underlying demand for RCM services (which in turn will reflect forecasts of peak demand), as well as (b) the impact that the grandfathering arrangements have on overall supply. In our modelling, we have made the simplifying assumption that these conditions will not inhibit a battery from monetising the services it could potentially provide into the RCM. To the extent that this assumption is not correct and a battery can't monetise the services it could potentially provide into the RCM, then the contribution competitive markets make to overall revenue generation reduces to 45% (with this solely reflecting the price arbitrage benefits provided by operating into the balancing market). The requirement to de-rate the battery to reflect a 4-hr capacity is based on information provided to us by EPWA.

It should be noted that it is possible that a grid-side battery could be used to provide services into the Essential System Services (ESS) market (i.e., Ancillary Services) as well as providing a means for managing over-voltage events in the distribution network (voltage network support).

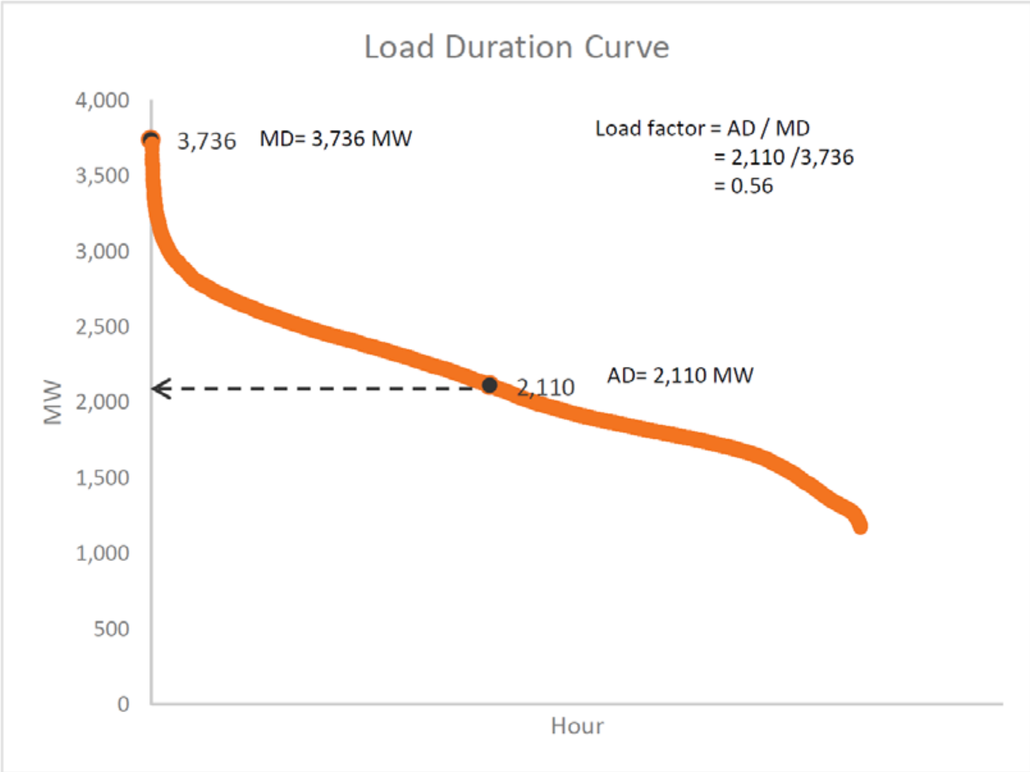
For simplicity, we have assumed that these are not able to be offered in conjunction with the services that are being offered into the Balancing Market and RCM market in our modelling. To the extent that a grid-side battery is able to co-optimise the provision of energy-market services and ESS/voltage network support, it would increase the amount of revenue that could accrue from the operation of the battery and change the proportion of overall revenue that is accrued from the provision of services into competitive markets.

Results of Task 1B

To provide context regarding the proportion of WA's peak demand and FCAS market that could be supplied by grid scale batteries it is worthwhile understanding the load duration curve that impacts the SWIS. As an accompaniment to its most recent regulatory proposal (2017), Western Power provided the load duration curve shown in the figure on the following page.

Figure 2: Load Duration Curve

Figure 7: Load factor calculation example



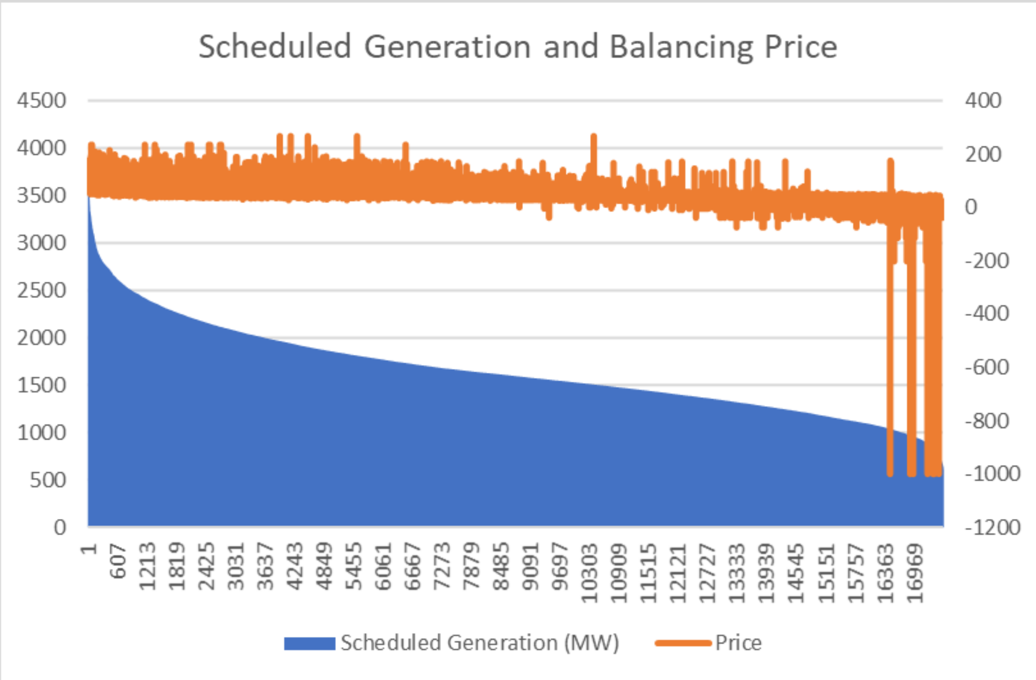
Source: Western Power, *Attachment 7.3.1, Connections, Energy and Demand Forecast Methodology, Access Arrangement Supplementary*, Confidential 2 October 2017

That graph was accompanied by the following text:

> *A low load factor indicates a relatively low level of network utilisation. Figure 7 indicates that demand exceeds 3,000 MW for a short* ***duration over a few hours of the year****, typically* ***a few days each summer****. An ideal load factor would be a horizontal line, indicating a consistent level of demand over a given year* ***[emphasis added]****.*

While this data is over four years old, it broadly aligns with information gleaned from the 2020 Balancing Market data, which suggests a similar load shape (for scheduled generation). That data also indicates that there is a general relationship between scheduled generation and the balancing price (Multiple R of 0.57); and moreover, that there is a particularly strong relationship between when low levels of scheduled demand are required, and much lower (and, in many cases, negative) prices. This can be seen in Figure 3 on the following page.

Figure 3: Scheduled Generation and Balancing Price



The CY2020 Balancing Market Data indicates that there were actually 131 half-hour periods above 3000MW. This is more than what Western Power indicated in their 2017 document. Even still, this is only about 65hours in total across a year, or about 0.74% of the time. It is also the case that 15 of the top 16 half-hour periods (which range from a maximum of 3822MW down to 3403MW) occurred on only 2 days – equivalent to 4 hours per day, which aligns with EPWA's advice with regards to the de-rating of batteries to 4 hours for the purposes of the RCM.

The small number of hours in which high demands for scheduled generation occur, and the spread of those hours across days, means that even a relatively small number of grid-sized batteries may impact the operation of some peaking plants as well as price in the WEM. That said, it seems unlikely that 400MW[37] of grid side batteries will be installed in the WEM in the near term.

However, if a grid-side battery's capacity were offered into the LFAS market, a single 5MW battery would represent in the order of 5.8% of the current capacity in that market (85MW, as per AEMO 2020, *Ancillary Services Report for the WEM 2020*, page 13).

37 This is the difference between the maximum amount of scheduled generation in 2020 and the 16th ranked half hour (i.e., 4 hours per day across two peak days).

Results of Task 1C

A high-level estimate of the proportion of a grid-scale battery's annualised costs that can be met by network augmentation deferral costs is in the order of 27%. This is based on the information presented in the earlier table reflecting the results of Task 1A, along with an assumed capital cost of $850/kWh[38], and the battery having a 15-year life. It disregards any degradation in the battery over that time horizon and assumes that network support costs will remain the same across the forecast time horizon.

This is summarised in the following table.

Table 4: Proportion of a grid-scale battery's annualised costs that is met by network support payments

Revenue Stream	Value	Assumptions
[A] Annual Network Support Revenue	$225,000	See the table accompanying the results of Task 1A (NB: Transmission plus Distribution)
[B] PV of [A] Network Support Revenue	$2,335,423	PV based on 15 years, WACC of 5%
Upfront cost of battery	$8,500,000	10MWh battery, multiplied by $850/kWh (OGW assumption based on published information)
Proportion of upfront cost of battery	27.48%	Based on [B] / Capital Cost ($850/kWh*10MW*1000)
Proportion of annualised cost of battery (based on building block model)	Year 1 - 19.61% Year 5 - 21.76% Year 10 - 25.21% Year 15 - 29.97%	Building block approach; O&M = 2% of CAPEX; straight line depreciation over 15 years; WACC of 5%.

38 https://energyconsumersaustralia.worldsecuresystems.com/Report%20community%20battery%20ownership%20models%20Feb2020.pdf (page 19) for details