2020 ENERGY SECURITY BOARD

POST 2025 MARKET DESIGN

Response to Consultation Paper

October 2020

1. Introduction

Stanwell Corporation Limited (Stanwell) welcomes the opportunity to comment on the Energy Security Board (ESB) Post 2025 Market Design Consultation Paper September 2020 (Consultation Paper).

This submission contains the views of Stanwell and should not be construed as being indicative or representative of Queensland Government policy.

Stanwell is a major provider of electricity to Queensland, the National Electricity Market (NEM) and large energy users throughout Australia. We own and operate two coal fired power stations, providing reliable and affordable energy, whilst exploring new generation and storage technologies that will help reduce emissions for tomorrow.

We commend the ESB for its works to date but are extremely concerned with the lack of detail about the proposed options for further consideration that has been provided in the Consultation Paper. The reform options are largely still at the conceptual level without having even a high-level cost/benefit analysis done to date.

Given the lack of detail and absent even a basic cost/ benefit analysis, Stanwell considers that the ESB's stated timeframe for evaluating and considering submissions to this paper and finalising a suite of recommended options by late December 2020 or early January 2021 is unrealistic at best, hasty at worst. Stanwell considers that the existing timeframe is restrictive and unlikely to allow the ESB to meaningfully consider all stakeholder feedback in relation to this Consultation Paper prior to writing and presenting an Options Paper to the Energy National Cabinet Reform Committee (formerly COAG Energy Council) in early 2021.

Stanwell encourages and is willing to support the ESB in seeking a 3-month extension from the Energy National Cabinet Reform Committee in order to properly consider stakeholder submissions, assess and develop options in further detail and consult with stakeholders on the options paper *prior to* its finalisation and submission to Energy National Cabinet Reform Committee.

Stanwell welcomes the opportunity to further discuss this submission. Please contact Ian Chapman on (07) 3228 4139 or ian.chapman@stanwell.com.

2. Context

The NEM is transitioning from a centralised to a decentralised, democratised energy system that is driven by customer value, increased variable renewable energy (VRE) sources and less synchronised generation.

This shift is presenting new challenges in the NEM and an electricity system that was designed around power being provided in one direction (to customers), primarily by large synchronous, scheduled generators. Dispatchable large-scale generators are now being squeezed out of the market during the day when VRE is typically at its peak output but are still required to meet demand during morning and evening peaks. In addition, there is a drive to encourage demand-side participation in the market from both commercial and residential scale, adding to the complexities faced by the market operator to keep the system secure and stable, and creating technical and commercial challenges for established market participants.

This has led to questions as to whether the existing market design and its associated systems and regulatory arrangements remain fit for purpose in order to meet the changing needs of the system and customers.

Localised challenges around security and reliability have emerged recently and these have largely been able to be managed through the existing arrangements in the NEM. However, as more VRE and demand-side participants enter the market, and traditional synchronised generation sources exit as they reach the end of their operational life, the current mechanisms will likely not be able to respond sufficiently and/or economically to deliver a secure energy supply to customers.

We are seeing increased out-of-market interventions on the part of the market operator in order to keep the system stable and reliable. Additionally, we see increasing actions from various governments that are well intentioned but disruptive to natural market investment signals.

These government interventions undermine the confidence of private sector investors who see greater risk of future interventions that undermine their ability to make a return on their capital investment. This results in a cycle where only governments can invest, deploying taxpayer funds into non-commercial markets.

A functional market that can operate without unnecessary intervention and attract genuine commercial investments will be the most efficient and cost-effective pathway as we transition to higher levels of renewable generation.

Any reform package proposed must not only address system needs, but also instil confidence in both parties that the market and its mechanisms can meet the objective of secure and reliable supply to customers at the most efficient cost.

The market and system will need to change and evolve in order to respond to these challenges, but the question is how extensive do those reforms need to be, and at what cost?

3. Current market design challenges and alternative solutions

Stanwell agrees with the ESB's identification of the broad four challenges that any market redesign must address, being:

1. meeting customer needs;
2. managing variability and uncertainty in power system flows;
3. incentivizing capital replacement; and,
4. recognizing demand flexibility and integrating DER.

Stanwell considers that if the last three are done effectively, efficiently and in a cost-effective manner, meeting customer needs and expectations should flow out of that.

As will become evident when reading our submission, Stanwell considers the missing essential system services (ESS) markets is the most immediate challenge for the NEM and is our top priority reform initiative. Asynchronous and synchronous generators, consumers, network service providers and market bodies are impacted by the failure of a market to manage ESS. By not valuing ESS, this not only impacts on the current providers of these services (mostly existing synchronous generators) but provides no investment signal to future providers as existing sources exit the market over the next two decades.

We see the need for managing the variability and uncertainty in power system flows as another immediate challenge that can and should be addressed in the relatively short term. This issue has been identified by market bodies and rule change proponents as an area whereby advances in participant capabilities need to be reflected under the National Electricity Rules (NER) in order to optimise and maintain system security and reliability.

Stanwell considers that unless the uncertainty and variability impacts of both large and small scale VRE on the system is addressed, maintaining system stability and reliability in an efficient way will become increasingly challenging and expensive. We note the AER's recent rule change request regarding semi-scheduled generator and dispatch instructions[1] aims to address some of these challenges in relation to large scale VRE. Stanwell will be making a submission on the AEMC consultation paper in support of this rule change once it is released.

Incentivising capital replacement is a longer-term challenge that should be able to be addressed by a combination of addressing the missing ESS markets, as well as enhancing the existing resource adequacy mechanisms. As noted above, the biggest challenge faced by the sector in relation to incentivizing the investment in the right technologies at the right time is the threat of out-of-market interventions by market bodies and governments.

Stanwell sees out-of-market interventions as the biggest threat to efficient investment in required replacement technologies. If the market mechanisms are developed appropriately and allowed to occur as designed, investment should occur when and where it is needed to meet the market needs. A functional market that can operate without unnecessary intervention will be the most efficient and cost-effective pathway as we transition to higher levels of renewable generation.

Stanwell sees the potential benefits of integrating DER into the wholesale market but sees this as a longer-term objective that is less of a priority than some of the other challenges outlined above. We contend the primary objective for DER integration in the short-term should be on mitigating the current technical challenges stemming from the current fleet of uncontrollable DER. In terms of demand response, Stanwell notes the NEM currently has multiple large loads that could contribute to delivering a reliable and secure system if the rules provide the right framework, incentives and mechanisms for their participation.

[1] https://www.aemc.gov.au/rule-changes/semi-scheduled-generator-dispatch-obligations

Demand response participation incentive should be targeted at these large loads where most of the value to the system lies. Stanwell considers that by starting with large customers first, an eventual way forward for small customer participation models to be developed should be much easier. Scheduling large loads would significantly increase AEMO's visibility of the demand side at the transmission network level and avoid the potential negative impacts on the market of non-scheduled demand-side participation.

4. Stanwell's priority reform positions

Stanwell's detailed assessment, responses and conclusions in relation to the proposed options under the Consultation Papers' seven market design initiatives (MDIs) are provided at Appendices A to G. Stanwell considers that many of the immediate issues and concerns discussed in Section 3 above can be largely addressed through enhancing the existing framework, whilst maintaining a long-term vision of a decentralised, democratised energy system driven by customer-value.

The longer-term and more radical reform options proposed under the MDI's require very careful consideration to ensure that they meet the National Energy Objectives (NEO) and meet consumers needs at the most efficient cost. Most of the longer-term options currently lack the appropriate detail to be adequately assessed in relation to their potential effectiveness, costs and benefits. There are a number of "no-regrets" options outlined in the Consultation Paper that could progress as a priority, such as the proposed initial development of market-based procurement of essential system services (ESS) and creation of the unit commitment for security.

More complex options, including innovative design spot market based ESS procurement and ahead mechanisms require further work before stakeholders would be able to provide meaningful comment on their potential benefits and effectiveness in meeting market participant and customer needs.

Stanwell recommends that the ESB undertake detailed analysis and thorough and transparent cost/benefit analysis of its preferred options once chosen, and engage with stakeholders once this assessment is complete, prior to their presentation to Energy National Cabinet Reform Committee.

Stanwell's assessment of the MDIs has identified our top three positions on the proposed reform options. These are:

- Ensuring that all essential system services are valued;
- Identifying alternative solutions to the drastic transformation of the market as proposed under the transmission access and COGATI MDI; and
- Not supporting the development of an ageing thermal generation strategy.

Our positions on these three MDIs are summarised below, and discussed in further detail at Appendices B, C and G.

MDI-C: Essential System Services (ESS)

Stanwell sees the valuing of ESS as a top priority for the ESB's reform program and is supportive of the ESB's focus on this MDI. We contend that transparent and technology neutral market mechanisms must be designed and implemented to ensure their continued provision at least cost to consumers.

As we stated in our submission to the Australian Energy Market Commission's (AEMC) System Services Rule Changes consultation paper[2],

> *"Stanwell considers it fundamental that a suite of complementary services is defined and consistently valued (even if that value is at times low or even negligible). The continued provision of uncompensated system services by a decreasing proportion of the market is not sustainable, as observed by increasing out-of-market interventions[3]."*

[2] Stanwell Corporation Limited, Submission to the AEMC System Service Rule Change Consultation Paper 2020

[3] Reliability Panel, 2019 Annual Market Performance Review, Final report, 12 March 2020, p. 147.

Stanwell considers that addressing the ESS "missing markets" will not only resolve the technical challenges the market operator will face in keeping the system stable as we transition to higher levels of VRE, but also address consistent themes that run throughout the ESB's work, including:

- Meeting consumer needs;
- Strengthening investment signals to continue to operate existing capacity and establish new sources of firming or dispatchable plant that will maintain resource adequacy;
- Promoting competition and help keep prices as efficient as possible for consumers;
- Providing certainty to market bodies and governments that the energy system will continue to operate securely; and
- Addressing structural changes to our generation mix and the technology used to manage demand and supply.

Whilst Stanwell is generally supportive of the ESB's proposed development roadmap for ESS, the ESB must provide detailed information to stakeholders about how each mechanism is expected to work in order to assess which procurement method is appropriate for each service.

Stanwell would like to raise its concern that under this MDI, the ESB is indicating that the provision of primary frequency response (PFR) will continue to be mandatory under a new procurement mechanism.

Stanwell would like to draw the ESB's attention to the Australian Energy Council's (AEC) Frequency Control Sub-group's supplementary submission[4] to the AEMC's Primary Frequency Response Incentive Arrangements rule change consultation. This submission outlines two potential pathways to replace the current mandatory PFR arrangements prior to their expiry under the three-year sunset clause. We encourage the ESB to consider the options presented by the AEC in developing a recommended PFR design and procurement option under this MDI.

[4] Australian Energy Council, Primary Frequency Response Incentive Arrangements, September 2020, https://www.aemc.gov.au/sites/default/files/2020-10/20200922%20AEC%20PFR%20submission.pdf

MDI-G: Transmission and access and the COGATI

Stanwell does not support the drastic transformation of the market as proposed under the COGATI MDI.

The proposed reform continues to lack a clear purpose and demonstrable marginal benefits despite multiple consultation processes and permutations. It will not address the issues it purports to address (e.g. investor certainty, disorderly bidding, generator revenue certainty). In its current state, the reform represents a costly, disproportionate approach to achieving incremental gains in dispatch efficiency.

Stanwell has significant concerns with the analysis of estimated implementation costs and modelled benefits. HARD software's estimated IT implementation costs appear to vastly understate implementation costs of both the Australian Energy Market Operator (AEMO) and market participants, and both NERA's modelling and analysis of the results overstate the potential benefits of the reform.

Most of the benefits of increased dispatch efficiency and better investment locations can be achieved without the cost and increased complexity of the proposed significant changes to the market design. To this end, there are several no-regrets actions can be implemented to improve locational signals ahead of investment decisions (e.g. redevelopment of the dispatch engine, producing network congestion maps, indicative "do no harm" requirements across the network).

MDI-B: Aging Thermal Generation Strategy (ATGS)

Stanwell does not support the development of additional ATGS measures.

There are several existing and transparent mechanisms that place obligations on *all* generators to report, disclose and notify market bodies of operational and financial circumstances that drive decisions to participate or withdraw from the market.

Stanwell contends the residual risks identified by the ESB in relation to the retirement of ageing generators, investment in new generators and the secure operation of the system can be sufficiently met through existing regulation and

market mechanisms, and initiatives under Essential System Services, Resource Adequacy Mechanisms and Ahead Markets MDIs.

Stanwell believes that the most efficient customer outcomes will be achieved by letting the appropriate market signals stimulate investment as it is required. Given the options proposed by the ESB for further consideration under this MDI are likely to distort market signals rather than enhance them, Stanwell contends that none of the proposed options should be progressed.

5. Stanwell's position on remaining MDI's

While acknowledging our top three priorities above, that is not to say that Stanwell is indifferent on the remaining MDIs. Below is a summary of our view and positions in relation to the other four MDIs outlined in the consultation paper. Stanwell's more detailed assessment and positions in relation to the options identified by the ESB for further consideration can be found at Appendices A, D, E and F.

MDI-A: Resource Adequacy Mechanisms

Free of market interventions, existing resource adequacy mechanisms provide adequate investment signals for the energy market but are insufficient for essential system services. Stanwell considers that if missing markets for essential system services are addressed through MDI-C, many of the concerns pertaining to investment in the right type and quantity of capability, competition promotion and certainty, will be addressed.

Whilst there are existing resource adequacy mechanisms for energy, Stanwell acknowledges that there could be merit in developing an operating reserve mechanism that enhances the real-time price of energy to better reflect the cost of providing secure, firm and dispatchable reserves.

We are also cautiously supportive of the ESB investigating options around a modified RRO in terms of improving risk management mechanisms and potentially aligning it with the 42-month notice of closure for generators.

Finally, Stanwell would support the ESB investigating consequential adjustments to the RERT, with the aim to ensuring the RERT remains as a last resort measure should other resource adequacy mechanisms fail to effectively address any projected shortfalls.

MDI-D: Scheduling and Ahead Markets

Stanwell welcomes further detail prior to progressing the implementation (or enhancement) of a Unit Commitment Security (UCS) analysis tool and supports the consideration of a range of procurement options for essential system services, both with extensive stakeholder consultation.

Stanwell does not support extending of scheduling and ahead mechanisms to energy, except for a very short-term operating reserve product.

We support the ESB's decision to not progress further investigation of a compulsory ahead market design. Our view is this option would be overly complex, expensive and would limit flexibility within the NEM.

We consider that concerns relating to increased uncertainty of supply and demand can largely be addressed through initiatives that will enhance AEMO's ability to operate the system whilst equitably improving transparency and obligations for market participants. Initiatives include rule changes for:

- Semi scheduled generators[5];
- Wholesale demand response mechanism (WDRM)[6];
- Distributed energy resources (DER)[7]; and
- Generator registration and connection thresholds[8].

[5] AER, Semi scheduled generators – Proposed rule changes, https://www.aer.gov.au/publications/reviews/semi-scheduled-generators-proposed-rule-changes
[6] AEMC, Wholesale Demand Response Mechanism. https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism
[7] AEMC, Distributed Energy Resources Integration Updating Regulatory Arrangements Consultation Paper, 30 July 2020. Proponents SA Power Networks, St Vincent de Paul Society Victoria and Total Environment Centre and Australian Council of Social Science. https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources
[8] AEMC, Generator registrations and connections, 8 October 2020. https://www.aemc.gov.au/rule-changes/generator-registration-thresholds

MDI-E: Two-Sided Markets

Stanwell supports increased demand-side visibility and participation in the energy and system service markets.

Stanwell considers the goal of full participation is not appropriate and that further consideration should be given to a staged roll-out focussing on large energy users first and then reassessing with smaller consumers if the appetite to participate (founded on a clear understanding on obligations and how the market works) exists.
Stanwell would encourage a reassessment of the rules pertaining to small and large customers and whether making a clear distinction between the obligations of both parties would enhance customers (and retailers) ability to participate in markets.

MDI-F: Valuing Demand Flexibility and Integrating DER

Stanwell does not oppose continuous investigation into how the value of distributed energy resources can be optimised and contribute to the energy market. However, we recommend that this is a longer-term objective that will benefit from market bodies addressing existing market problems first.

6. Consideration of Cost to Consumers

Stanwell is concerned with the lack of acknowledgement by the ESB of the potential costs to customers as a result of the proposed reform options. While there is much discussion in the Consultation Paper regarding meeting consumer need and demonstrating value for money from a consumer perspective, the sheer scale of the proposed reforms is enormous. For most of the major reform proposals, such as resource adequacy mechanisms, ahead mechanisms and ESS, the costs to implement are likely to be significant. These are not trivial reforms and will require significant investment by both AEMO and market participants.

We recognize that many of the reforms outlined in the Consultation Paper are still at the conceptual stage and require a significant amount of development before a full cost/benefit analysis can be done. Regardless, we consider that the ESB must acknowledge that reforms will come at a cost, and benefits may not be realized in the short term.

If an extensive reform package is progressed, market bodies, participants and ultimately customers will be required to meet much of the cost prior to the mechanisms commencing (e.g. hardware and software upgrades, full systems development, compliance regimes and even training costs).

We only need to look at the cost to both AEMO and market participants to implement five-minute settlement (5MS) and global settlement (GS) rule change to give an idea of the scale of potential costs that would likely be incurred to implement some of the proposed reforms. Many of the reform options identified by the ESB are significantly more complex than 5MS and GS and are likely to be correspondingly much more costly to implement.

Stanwell does not dispute that some reforms are required to address the challenges of our transitioning energy supply, nor do we advocate for maintenance of the status quo, but costs and benefits need to be carefully and thoroughly examined and clearly communicated to all stakeholders. We are concerned that the sheer scope and complexity of the proposed reform package and associated overall cost of reform. These costs will ultimately be borne by customers (who have no choice), potentially outstripping any benefits to those customers, with profits accruing exclusively to market participants who benefit from the reform.

Stanwell is cautious of the risk of overstating benefits to support ideology of reform programs which could undermine the overarching objective of providing customers safe, reliable, secure and cost-effective electricity supply.

The cost assessment of COGATI as presented in HARD software estimates of participant' costs gives Stanwell concern that this is a significant risk. For transmission access reform, the HARD software estimates of both AEMO's and participants' IT implementation costs are considerably lower than the IT costs associated with 5MS implementation. HARD software's implementation estimate is in the range of $31.50 million to $37.85 million.[9] By comparison Deloitte's estimates of participants' costs for 5MS implementation are in the range of $380

[9] HARD software, A preliminary indication of the Information Technology Costs of Locational Marginal Pricing, p 60

million and $820 million.[10] Our observation of the COGATI implementation cost estimation, is that it is grossly under-estimated.

We implore the ESB to conduct thorough and comprehensive cost-benefit analysis of any proposed reforms, both individually and as a complete package, prior to finalizing a preferred market design model. Ideally, a peer or independent review of these estimates would give market participants much greater confidence in their veracity.

[10] Deloitte, Delayed implementation of the five-minute settlement and global settlement rules, p 9 and pp 33-34

Appendix A: Resource Adequacy Mechanisms, MDI-A

Resource adequacy at an efficient cost vs lowest cost

Market Design Initiative A has evolved from evaluating mechanisms[11], to more specifically relating to the delivery of "adequate resources through the transition, at lowest cost to consumers"[12].

Stanwell supports the ESB's focus on resources adequacy, but believes it needs to acknowledge that the lowest cost solution for consumers is not always the most efficient outcome and could lead to longer-term higher costs to consumers. We encourage the ESB to adopt the observation made by FTI Consulting:

> *"Achieving resource adequacy at an **efficient cost** is a fundamental objective for the **long-term interests of consumers**. Insufficient resources or network capability leads to load shedding, which can impose a (potentially significant) economic cost on consumers. At the same time, reliability should be delivered at value for money, whilst accommodating policy objectives, expected changes to the market, and technological advancements"*[13].

Stanwell considers that the most important and immediate challenge is to address the "missing markets" of essential system services (ESS), and to avoid exasperating existing over supply of non-dispatchable energy.

As illustrated in the 2020 Electricity Statement of Opportunities (ESOO), AEMO forecasts the NEM's annual operational energy consumption to decline until 2027-28[14], whilst NEM generation capacity[15] and annual generation[16] is expected to increase. Simplistically, signalling an oversupply to investors. Conversely, the unserved energy forecast[17] highlights that there is demand for firm dispatchable plant.

Stanwell is aware that some stakeholders have proposed solutions that are limited to only new builds. Stanwell insists that in the development of final solutions, the ESB does not pick winners and losers between technology types (i.e. chooses technology neutral solutions).

Furthermore, we strongly argue that existing market participants should be able to participate in new schemes to not only ensure an orderly transition to higher VRE penetration, but because existing fleet provide stability, liquidity and expertise when implementing new solutions. Ultimately, this will provide a more stable environment for new entrants.

Stanwell considers that industry should, in due course, be responsible for developing operational and technical standards to address resource adequacy mechanisms which could later be referred to as guidelines for participation assessment criteria.

Current resources adequacy mechanisms

Free of market interventions, existing resource adequacy mechanisms provide effective investment signals for the energy market but fail to do so for ESS.

Stanwell considers it fundamental that a suite of system services that are complementary to energy, is defined and consistently valued. The continued provision of uncompensated system services by a decreasing proportion of the market is not sustainable, as observed by increasing out-of-market interventions[18].

However, we acknowledge that to some extent, both energy and future essential system service markets will always be at risk to interventions. These should be minimised by the market operator and governments due to the cost implications for consumers[19], uneconomic outcomes for participants and the market.

[11] ESB Post-2025 Market Design, Directions Paper April 2020, p 8
[12] ESB Post-2025 Market Design, Consultation Paper September 2020, p 29
[13] FTI Consulting, Resource Adequacy Mechanism in the National Electricity Market, 16 July 2020, p 5
[14] AEMO, ESOO 2020, p 6.
[15] AEMO ISP 2020, Appendix 4 p 18
[16] AEMO ISP 2020, Appendix 4 p 24
[17] AEMO, ESOO, p 7

[18] Reliability Panel, 2019 Annual Market Performance Review, Final report, 12 March 2020, p. 147.
[19] Cost of interventions cost consumers $18.2 million FY17/18 and $15.7 million FY18/19. ESB, Health of the NEM 2019, p 20

> *"Some Government intervention is intended to improve reliable supply, but it can also distort the market and lower investor confidence"* [20].

Unfortunately, there is a disconnect between economic theory and political preference in relation to periods of high prices and investment announcements, leading to increasingly frequent and impactful intervention. As a result, the effectiveness of spot prices as a leading resource adequacy mechanism (RAM) has decreased sharply in recent years.

Noting this, Stanwell believes that one of the key tasks of the ESB in the Post-2025 Market Design development process is to build commonwealth and state governments' confidence that the final market design is fit for purpose and will allow the markets to meet the expectations and needs of energy customers. A functional (i.e. investment signalling) market that can operate without unnecessary intervention will be the most efficient and cost-effective pathway as we transition to higher levels of renewable generation. We do not under-estimate the enormity of this task but gaining this confidence and thereby reducing the temptation for inefficient out-of-market interventions, is imperative.

ESB proposed solutions

Operating Reserve

The FTI consulting report considers operating reserves mechanisms as another form of scarcity pricing, within the execution of the market dispatch. The market design for the operating reserves mechanism includes separate markets to schedule one or more types of operating reserves (and possibly other ESS).

> "*An operating reserve mechanism or market to complement the work being done to value unpriced services and to make demand more responsive to supply*"[21].

Stanwell considers that there is merit in developing a short-term operating reserve mechanism but note its potential to provide significant longer-term investment signals is limited. An operating reserve mechanism could provide some incremental enhancement to the real-time price of energy to better reflect the cost of providing secure, firm and dispatchable reserves.

Stanwell notes that the ESB will only consider this for development in conjunction with the ESS workstream MDI-C) and supports this approach. While the ESS section of the Consultation Paper considers operating reserves in the context of short-term adequacy, this section views it in the context of providing longer term investment signals. Stanwell sees the challenge for the ESB to develop a mechanism(s) that meets both of these objectives, but a careful and considered design may be able to achieve both.

Stanwell notes that reserves can be sourced from either the supply or demand side of the market. While this implies that reserves procured under an operating reserve mechanism could be supplied from either source, it is important for the ESB to consider the objective of incentivising investment in firm capacity in order to meet the objectives under this MDI. Care should be taken to ensure a correct balance of supply and demand side reserves with the required characteristics are facilitated under an operating reserve mechanism.

Enhanced RRO or Decentralised Capacity Markets

The aim of the Modified RRO or Decentralised Capacity Market option is to "provide a level of insurance"[22], and to some degree assurance, "that enough capacity exists to meet demand".

As presented in the Consultation Paper, this section lacks sufficient detail to properly assess options. We encourage the ESB to clarify exactly what elements of the RRO are looking to be enhanced and how the decentralised capacity market would operate.

The RRO has been in place for just over a year and has already been the subject of reform. Stanwell is cautious about any proposal for further changes to the RRO, particularly as there has not been time or application of the current mechanism to gauge its effectiveness. However, we acknowledge there may be some potential to enhance the current RRO to be more effective and efficient.

[20] ESB, Health of the NEM 2019, p 23
[21] ESB Post-2025 Market Design, Consultation Paper September 2020, p. 29
[22] ESB, Post 2025 Market Design Consultation Paper, September 2020, p 41

In Stanwell's response to the AEMC System Service rule change Consultation Paper, we state that,

> "*The introduction of day ahead, hourly, trading interval or dispatch interval reserve markets (operational or commitment) would not change a generator's long-term decision of whether to withdraw or decommit from the market, and that when reserve concepts are progressed by the various market bodies, the investment and operational timeframes that existing dispatchable synchronous generators need in order to make these decisions, should be considered through long-term contractual mechanisms*".[23]

Drawing from this earlier observation, we consider at high level how the RRO or decentralised model may improve the resource adequacy mechanism dilemma.

The RRO provides a framework that allows for both AEMO and jurisdictions to intervene in the market, by way of setting the reliability standard. If one considers that interventions will always happen, the RRO at a minimum provides a structured framework that participants and market bodies can respond to and manage expectations.

As it presently stands, the RRO provides limited support for short to medium term investment in firm, dispatchable sources.

Stanwell considers that if the ESB is looking to enhance the RRO, the following should be aimed at:

- Improving risk management and hedging opportunities for physical and/or financial certificates; and
- Aligning the contracting requirement of retailers (currently 12-24 months) with the notice of closure requirement on generators (42 months).

In relation to the second point, the different periods of time have created a mismatch for retailers and generators; retailers don't have to contract beyond 24 months while generators must commit (sometimes with no contracts) 42 months in advance. The misalignment of the 42 months' notice of closure requirement with RRO contracting periods impacts a generators' ability to make efficient operational and maintenance decisions as they approach their closure window.

Requiring retailers to contract 42 months in advance under a modified RRO would create an alignment between the contract market and notice of closure requirements, giving additional certainty of revenue streams to generators as they approach retirement or are considering entering the market.

RERT adjustments or Interim Reliability Reserves

Stanwell agrees with the ESB's assessment that overuse of backstop mechanisms such as RERT can undermine the efficient operation of the wholesale market and increase costs to customers.

Stanwell considers that the RERT is effective when utilised as a measure of last resort should other resource adequacy mechanisms not effectively address projected shortfalls. However, as noted in our submission to the AEMC's 2019 draft rule determination[24] Stanwell believes the recent extension to the procurement lead time from 9 months to 12 months will have implications for retailers and liable entities under the RRO. Stanwell's main concern is that the 12-month procurement lead time could result in AEMO tendering for RERT in the market at the very time retailers are finalising their contract positions under the RRO in preparation for their T-1 contract reporting obligation.

Stanwell views out-of-market procurement as having the potential to cause distortions in the energy market including withdrawal of generation capacity, dampening of investment signals, inefficient risk allocation and unpredictable reliability reserve costs[25].

We consider that a short term in-market operating reserve market which incentivises transparent, scheduled or dispatchable participation would provide a more beneficial incentive than the current RERT structure; rewarding in-market participation over out-of-market resources.

[23] Stanwell Corporation Limited, Submission to the AEMC System Service Rule Change Consultation Paper 2020, p 9

[24] Stanwell Corporation Limited, Enhancements to the Reliability and Emergency Reserve Trader – Response to the AEMC Draft Rule Determination, March 2019

[25] www.aemc.gov.au/sites/default/files/2019-02/Draft%20determination.pdf, p 117-118

Resource Adequacy Mechanisms conclusion

Existing resource adequacy mechanisms would be sufficient for providing investment signals in the *energy market*, if they are allowed to occur as designed without intervention. Initiatives developed under the ESB's Post-2025 Market Design process should aim to decrease the occurrence of interventions by governments and the market operator whilst allowing for appropriate investment market signals for both energy and ESS to occur naturally.

ESS markets are lacking, and development of those missing markets will help ensure appropriate investments are made to ensure the energy system remains stable and secure. It is fundamental that a suite of ESS markets that are complementary to energy are defined and those services are consistently valued, even if that value is at times low or even negligible.

Stanwell considers that there is merit in developing an operating reserve mechanism, noting its potential to provide significant longer-term investment signals is limited. However, it could enhance the real-time price of energy to better reflect the cost of providing secure, firm and dispatchable reserves.

Stanwell is cautiously supportive of the ESB investigating options around a modified RRO in terms of improving risk management mechanisms and potentially aligning it with the 42-month notice of closure for generators. We ask that the ESB develop this proposal in more detail that can then be socialised with stakeholders for further consideration.

Finally, Stanwell would support the ESB investigating consequential adjustments to the RERT, with the aim of ensuring the RERT remains as a last resort measure, should other resource adequacy mechanisms fail to effectively address projected shortfalls.

Appendix B: Aging Thermal Generation Strategy, MDI-B

The concern about disorderly generator exit

Since the short-notice closure of Engie's Hazelwood Power Station in 2017 there has been heightened sensitivity around the potential for further short-notice or unexpected exits of coal fired plants from the NEM in the future.

Since 2017, new measures have been introduced that build on pre-existing regulatory measures to further mitigate risks around plant closure to the market and customers. These include the requirement for plant to provide at least 42 months' notice of closure, introduction of the RRO and development of an integrated system plan. Stanwell notes the ESB only intends to progress options presented under this MDI if it finds sufficient evidence that there is still material security and reliability risks that should be addressed through regulatory change.

Stanwell's view is that investment in replacement generation for exiting thermal generators will occur most efficiently if the appropriate market signals are in place and allowed to occur without interference.

Risk assessment analysis

Stanwell considers that the ESB has, for the most part, correctly characterised the risks associated with disorderly or unexpected exit of coal fired generation to the market, future investment and costs to customers. The size (capacity) and capability (services) of generator exits at a particular time (or over a shorter period) will determine the scale of the risk posed if appropriate market mechanisms and signals are not in place to ensure investment happens at the right time to meet the market and system requirements.

As noted above, there are already several market and regulatory mechanisms in place designed to address and mitigate the risks associated with plant closure through market price signals, the contract market, publication of information and forward planning. These, combined with the notice of closure requirements and the RRO, has reduced the risk of unexpected thermal generation exit significantly reduced since Hazelwood's closure.

In addition, the implementation of market-based initiatives under the Resource Adequacy Mechanisms, Essential System Services and Two-Sided Markets MDI's should further reduce the identified risks and complement the existing mechanisms in the market. The Resource Adequacy Mechanisms and Essential System Services MDI's in particular should help ensure that the essential system services provided by thermal generators are appropriately valued alongside the energy they generate.

This should create an environment where investment and retirement decisions can be made in light of all material considerations, improving confidence in the market design. If the combined revenue opportunities from the services a generator provides are sufficient it is more likely to remain in the market than in a design where valuable services are not explicitly recognised, and appropriate compensation provided. Conversely, where combined revenues are below cost it is likely to be due to ample supply of each service and therefore retirement would have a low impact on the market.

However, the effectiveness of these mechanisms is dependant on the market being allowed to work as intended and this means allowing prices for energy and system services to rise at times of scarcity without intervention. Interventions that dampen these signals will likely result in reduced investment appetite and earlier exits from the market.

As the ESB has noted in its Consultation Paper, there is still much debate as to whether governments will tolerate the required periods of volatility and higher prices required to stimulate investment and provide sufficient revenue to remaining thermal generators to recover long run marginal costs and maintain their plant. These higher prices are a feature of the market designed to ensure market participants remain both viable and reliable up to their nominated closure date. Stanwell sees this as the greatest residual risk to an orderly exit of thermal generators and investment in new energy and system service sources.

As noted in our assessment of the Resource Adequacy Mechanisms MDI at Appendix A, Stanwell believes that one of the key tasks of the ESB in the Post-2025 Market Design development process is to build commonwealth and state governments' confidence that the final market design is fit for purpose, and discourage out-of-market interventions that will disrupt investment signals, increase risk of disorderly exit of plant, and ultimately increase costs to customers.

Stanwell consider it is unlikely the ESB will engender such confidence in policy makers while it refers to the increased revenues to remaining thermal plant by way of higher spot prices after the exit of another generator as “rent-seeking” or “excess profits”. All markets are designed to respond with higher prices at times of scarcity. The reality is that at those times *all* participants in the market will benefit from increased revenue regardless of fuel source, not just remaining thermal generation.

Such labels give the impression that this outcome is somehow inefficient just because some thermal generators will benefit, while ignoring the fact that these are the exact signals that are needed in the market to stimulate new investment or retain existing resources.

ESB proposed solutions

Stanwell does not support further consideration of the options proposed by the ESB under this MDI. The current mechanisms and proposals under other MDIs in the Consultation Paper should provide enough certainty around planned closure dates for thermal generation and allow appropriate market signals to attract new participants into the market to replace existing capacity and capabilities.

The Grattan Institute proposal would impose a significant financial burden on industry (including customers) which could have the unintended consequence of undermining the ongoing financial viability of some generators. For example, if the Grattan Institute model was implemented as proposed it would effectively impose a financial liability of about $4 billion on thermal generators over the next ten to twelve years as shown in Figure 1.

It is likely the escrow payments would need to come from operating cashflows. Our initial assessment indicates that there is significant risk that thermal plants will be uncommercial for much of the transition. Even the proponents of this model recognise that the cost of escrow payments “would probably be borne by consumers in the form of higher electricity prices, and some by generators through lower profits”[26].

This arrangement would lead to distortions in the market as the quantum of the escrow payment would vary between generators, depending on their age. This would not be the most efficient outcome for either customers or market participants.

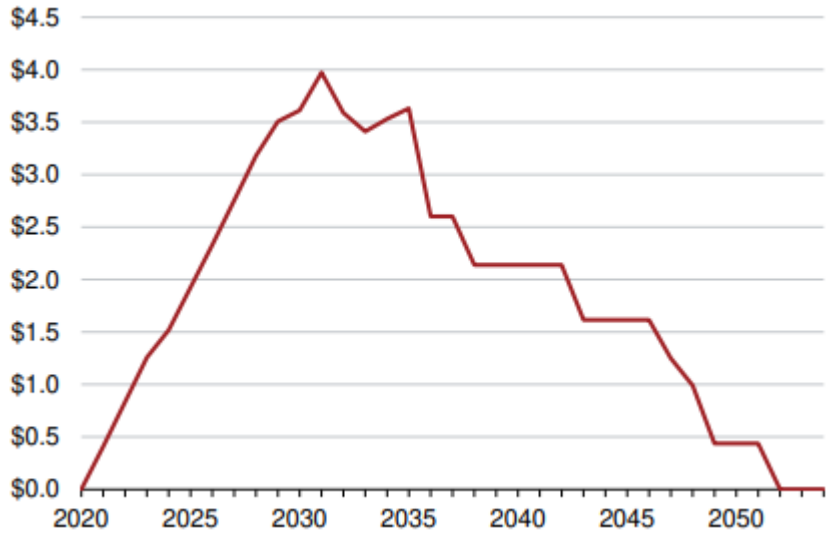

Figure 1 Funds in escrow would grow to almost $4 billion before declining as coal plant closes. Source: Grattan Institute 2019[27].

Regarding the proposal for regulated or negotiated arrangements between AEMO or governments and thermal generators, Stanwell believes this is also likely to lead to market distortions by forcing generators to stay in the market when it does not make commercial sense to do so. This proposal more closely fits the true definition of rent seeking than the current application of the term by the ESB. These arrangements would supress market signals, including energy spot and system services prices and deter required investment in replacement generation plant.

[26] Grattan Institute, *Power Play: How governments can better direct Australia’s electricity markets,* October 2019, p 33

[27] Grattan Institute, *Power Play: How governments can better direct Australia’s electricity markets,* October 2019, p 33

Finally, Stanwell notes that AEMO already undertakes contingency scenario planning, and the ESB's suggestion of potentially implementing separate planning processes at the jurisdictional level does not make sense unless it feeds directly back into the NEM wide processes. Creating additional layers of scenario planning increases the risk of conflicting and/or inconsistent planning outcomes.

Aging Thermal Generation Strategy conclusion

As noted above, Stanwell believes that the existing regulatory mechanisms designed to help coordinate the entry and exit of generation and reduce risk, as outlined in the Consultation Paper, and proposed new market reform initiatives under other MDI's will provide sufficient notice and market derived investment signals to stimulate appropriate investment and demand responses to the progressive exit of aging thermal generation from the NEM.

Stanwell strongly opposes consideration of any proposals that fall outside of the market design and believes that the most efficient customer outcomes will be achieved by letting the appropriate market signals stimulate investment as it is required. Given the options proposed by the ESB for further consideration are likely to distort market signals rather than enhance them, Stanwell recommends that none of the proposed options under this MDI be progressed.

Appendix C: Essential System Services (ESS), MDI-C

Why valuing ESS is essential

The valuing of ESS is a top priority of the ESB's reform program and Stanwell is supportive of the ESB's focus on this MDI.

The economic fundamentals of the energy market have changed significantly in recent years requiring all participants (synchronous and asynchronous) to re-evaluate capital and operational decisions including financial contracting, maintenance cycles, fuel contracts and dispatch profiles in the spot market intra-day and on a long-term basis. Stanwell is concerned that the provision of ESS has been assumed as being continuously and freely available at historical volumes until the retirement date of generators.

Without market mechanisms that explicitly value ESS, market participants are unable to consider the value of the provision of these services, and the importance of them to the broader market, when making operational and capital planning decisions. Effectively, a synchronous generator is only able to make operational and capital decisions, including retirement, based on the energy price. This is despite the importance, and therefore implied value of the other system services they provide to the network and system operators.

It is clear that the current market arrangements are not providing the required signals into the market for the continued and replacement provision of ESS. In our submission to the AEMC, System Service Rule Change Consultation Paper[28] Stanwell noted that without market mechanisms that explicitly identify, value and allow for the procurement of all essential system services, the security and reliability of our energy system will deteriorate. Market bodies and all market participants need a framework established around these services so they can make informed and more accurate decisions when it comes to investment, design and operational considerations.

Stanwell maintains that the continued provision of uncompensated system services by a decreasing proportion of the market is not sustainable, as observed by increasing out-of-market interventions[29]. In addition, without ESS being appropriately valued there are no market signals to incentivise new providers to enter the market as traditional providers of these services exit over the next two decades.

Stanwell agrees with the ESB's assessment and AEMC's summary that without changes that will incentivise the provision of required volumes of ESS consumers are likely see higher costs and more outages because of:

- More interventions to maintain system security with associated costs;
- Increased curtailment of lower-priced variable renewable energy (VRE);
- Poor frequency control, potentially breaching standards and making the system less resilient to disturbances;
- Greater complexity in operations and planning resulting in inefficient outcomes; and
- Increased risk of cascading failures leading to load shedding.[30]

As noted by the ESB, use of contracts-for-difference could be used to mitigate any energy price losses of participants resulting from being called on to provide ESS[31]. As the market matures and new sources of ESS enter (not necessarily linked to energy provision), the need for this type of contracts should fall away.

ESB proposed solutions

Stanwell notes that for any of the options proposed under MDI-C to work effectively, the proposed Unit Commitment Tool under the scheduling and ahead mechanisms MDI should be developed to identify, quantity, report and value all essential system services.

[28] Stanwell Corporation Limited, Submission to the AEMC System Service Rule Change Consultation Paper 2020, p 2

[29] Reliability Panel, 2019 Annual Market Performance Review, Final report, 12 March 2020, p 147

[30] https://esb-post2025-market-design.aemc.gov.au/

[31] ESB, Post 2025 Market Design Consultation Paper, Sept 2020, p 62

Operating Reserve procured by spot market

As stated in Appendix A of our submission, Stanwell supports developing an operating reserve mechanism which should enhance short-term operational confidence that demand can be met at times where the supply and demand balance is tight.

We agree with the ESB's approach of developing a reserve mechanism that address both short-term adequacy, in line with this MDI, as well as enhancing longer-term investment signals. Stanwell sees the challenge for the ESB is to develop a mechanism(s) that meets both of these objectives, but as previously stated a careful and considered design should be able to achieve both.

The ESB has indicated that it may look to procuring operating reserves as an ESS measure by a spot market under a sloping demand curve framework. Stanwell questions the applicability of the sloping demand curve in this circumstance, given the demand curve for unscheduled demand is determined at the market price cap. We suggest that a more appropriate approach would be to apply an incremental change to existing mechanisms. For example, if the operating reserve is for 30 minutes ahead, this could be achieved by setting demand for these reserves in line with the largest contingencies as currently occurs for the Lack of Reserve triggers.

Primary Frequency Response

Stanwell is pleased that the ESB has identified the development of arrangements to incentivise primary frequency response (PFR) ahead of the sunset of the current mandatory provisions in 2023. However, we are concerned that under the ESB's possible proposed roadmap of procurement and scheduling options for essential system services[32] it appears the provision of PFR by capable generators will continue to be mandatory.

Stanwell strongly opposed the mandatory PFR solution proposed by AEMO in our submission to the AEMC's Mandatory Primary Frequency Response Consultation Paper in October 2019[33]. While we recognised the need for effective frequency control in the NEM, our submission outlined that the mandatory requirement for PFR was unlikely to achieve certainty of improved frequency control, would impose significant costs and undermine investment signals for the provision of PFR in the future.

If the mandatory provision of PFR from all capable generators remains beyond the current interim arrangements there is still a likelihood that proper investment signals will be lacking in the market. Without these signals, new sources of PFR are not incentivised to enter the market and the system may eventually not have the effective PFR capability it requires in all network regions. Even if new sources are mandated, AEMO has already acknowledged that the natural headroom available now to provide PFR will decline, as non-synchronous generators tend to operate at their maximum potential output [34].

Stanwell continues to support the development of a market or other incentive-based solution as envisaged in the AEMC's 2018 Frequency Control Frameworks Review (FCFR), which was jointly agreed by AEMO and the AEMC.

Stanwell would like to bring to the ESB's attention a supplementary submission to the AEMC's Primary Frequency Response Incentive Arrangements rule change consultation made by the Australian Energy Council's (AEC) Frequency Control Sub-group[35]. This submission outlines two potential pathways to replace the current mandatory PFR arrangements with preferable market-based options. Stanwell encourages the ESB to consider the options presented by the AEC in developing a recommended PFR procurement design option under this MDI.

[32] ESB, Post 2025 Market Design Consultation Paper, Sept 2020, p 72
[33] Stanwell Corporation Limited, Primary Frequency Control – Response to the AEMC Consultation Paper, October 2019.

[34] AEMO, Response to request for advice — Frequency control frameworks review, March 2018, p.8-9
[35] Australian Energy Council, Primary Frequency Response Incentive Arrangements, September 2020, https://www.aemc.gov.au/sites/default/files/2020-10/20200922%20AEC%20PFR%20submission.pdf

Frequency Control

Stanwell considers there is merit in developing a fast frequency response (FFR) market as proposed by Infigen Energy[36] that includes inertia within the current FCAS market framework[37].

We do urge caution in trying to co-optimise too many elements of the energy market that could be provided separately by different technologies. A technology neutral approach must be considered throughout all options to allow not only for a level playing field, but to allow for innovative design and technology to advance. In saying that, where the market operator and systems such as the National Electricity Market Dispatch Engine (NEMDE) can co-optimise between providers this could result in the most efficient cost outcome.

Noting the above, in our response to the AEMC System Service Rule Change Consultation Paper Stanwell stated,

> *"As it stands, section 3.3, 3.4, 4.3 and 4.4 of the FCAS Market Ancillary Services Specification (MASS) explicitly excludes inertial response from being rewarded by the existing fast service mechanism.[38] This premise may have been made given the type of technology assumed to be available at the time, or under the incorrect assumption that most if not all generators would be synchronous, and synchronous generators will continue to operate as they have done in the past. Stanwell suggests that in the absence of mechanisms for the provision of inertia, the services procured in an FFR market should include inertial response. This would increase the number of sources for fast response (potentially lowering costs to consumers) and partially offset losses in the wholesale market when the regional reference price is lower than synchronous generators' short-run marginal costs".[39]*

Stanwell supports the ESB's assessment that FFR be provided under a spot-market based mechanism and suggests that the Reliability Panel is the appropriate body to determine the required outcomes through the Frequency Operating Standard. Given the Reliability Panel's current responsibilities and expertise in relation to setting Frequency Operating Standard and its broad independent membership it is logical that this body also set FFR standards.

In relation to the development of a demand curve for Frequency Response, Stanwell notes that this could be considered as a longer-term option once assessed in more detail. At this stage it appears that a demand curve framework is unlikely to be able to be applied to FFR where it is co-optimised with other system services.

Stanwell does not oppose the ESB working with the AEMC on exploring potential demand curve options but is not able to provide meaningful comment until design options have been developed in more detail and shared with stakeholders for consideration.

Provision of Inertia and System Strength

Stanwell notes the ESB's preference to initially move towards structured procurement of both inertia and system strength and investigate options to establish spot markets for these services. Spot-based mechanisms could eventually work alongside structured procurement arrangements.

As noted in our response to Frequency Control above, Stanwell supports the development of an FFR market including inertia within the current FCAS market framework as proposed by Infigen Energy. However, Stanwell would caution against moving to a spot-only procurement mechanism for inertia. Solutions must be technology neutral and achieve efficient cost outcomes for consumers. If a spot-only outcome is pursued, the effectiveness of the solution will fail to provide a core objective of providing a level of assurance to market operators and governments, which would likely result in the cycle of interventions continuing.

As such, we support the ESB investigating options that would enable inertia to be procured through a combination of spot-market mechanisms and/or via short-and long-term contracting arrangements.

[36] Infigen Energy, Operating Reserves and Fast Frequency Response Rule Change, March 2020, https://www.aemc.gov.au/sites/default/files/2020-03/ERC0296%20Rule%20change%20request.pdf
[37] Stanwell Corporation Limited, Submission to the AEMC System Service Consultation Paper 2020, p 7
[38] AEMO, Market Ancillary Service Specifications, July 2020, p 13
[39] Stanwell Corporation Limited, Submission to the AEMC System Service Consultation Paper 2020, p 8

We also support further exploration of the option for structured procurement for inertia combined with other system services (including voltage control and system strength) as proposed by ERM Power and CS Energy[40], known as the Power System Security Ancillary Service (PSSAS).

The ESB has identified three different interim arrangements whereby system strength could be procured through non market-based solutions including mandatory technical limits, TNSP emergency shortfall backstop rules, or a market based multi-year contracting solution. Stanwell believes there are merits in each option.

Maintaining the existing obligation on TNSPs to mitigate identified shortfalls in system strength is a valid backstop measure, and where possible improvements should be made. This could include allowing multi-year contracting which would provide additional assurance and security for providers of the required service(s).

Mandatory technical limits will be more challenging and has the potential to create winners and losers. If this option is pursued Stanwell recommends establishing technical limits but allow participants to make the commercial decision whether to provide system strength by way of updating existing assets or investing in new technologies, if it makes sense for that participant.

Essential System Services conclusion

Stanwell sees the valuing of essential system services (ESS) as a top priority for the ESB's reform program and is supportive of the ESB's focus on this MDI. The continued provision of uncompensated system services by a decreasing proportion of the market is not sustainable, and transparent and technology neutral market mechanisms must be implemented to ensure their continued provision at least cost to consumers. Stanwell considers it fundamental that a suite of complementary services is defined and valued at all times, even when supply of these services outstrips demand.

Stanwell generally supports the ESB's proposed development roadmap for the ESS MDI but is not convinced that moving exclusively towards spot market-based procurement mechanisms is entirely appropriate for inertia and system strength. In addition, while supportive of the development of an operating reserve mechanism, we do not agree that a demand curve framework would be an appropriate procurement method for this service.

Stanwell is concerned that the ESB is indicating that the provision of primary frequency response (PFR) continue to be mandatory under a new procurement mechanism. Stanwell notes the Australian Energy Council's (AEC) Frequency Control Sub-group has made a supplementary submission to the AEMC's Primary Frequency Response Incentive Arrangements rule change consultation. The submission outlines two potential pathways to replace the current mandatory PFR arrangements. Stanwell encourages the ESB to consider the options presented by the AEC in developing recommended PFR design and procurement options under this MDI.

[40] ERM Power, RE: System Services Rule Changes, Aug 2020, https://www.aemc.gov.au/sites/default/files/documents/rule_change_submission_-_erc0290_-_erm_power_-_20200820.pdf

Appendix D: Scheduling and Ahead Mechanisms, MDI-D

Several problems have been considered throughout the evolution of scheduling and ahead market initiative, including dealing with uncertainty and "firmness" of supply and demand sources, increasing asynchronous generation, increasing out-of-market interventions and investor confidence.

Stanwell welcomes the ESB's refined focus of this MDI on mechanisms to identify, value and procure essential system services. As noted throughout this submission, we support finding new markets in ESS and the establishment of frameworks and mechanisms that will enable ESS markets.

Except for very short-term operational reserve markets as discussed in Appendix A and C of our submission, Stanwell does not support the extension of this MDI to energy. Stanwell considers that the pre-dispatch mechanism for scheduling of the energy market is an effective mechanism if all market participants follow the rules and the rules are enforced. The cost of investigating and potentially extending scheduling and ahead mechanisms to include energy will be an in-efficient use of customer money.

Furthermore, there are a number of rule change projects underway that aim to enhance AEMO's ability to operate the market and reduce uncertainty from both supply and demand sources, including:

- Semi scheduled generators[41];
- Wholesale demand response mechanism (WDRM)[42];
- Three rule change requests aimed to "better facilitate the efficient integration of distributed energy resources (DER) for the grid of the future"[43]; and
- Generator registration and connection thresholds[44].

Stanwell recommends that the ESB allows these processes to progress to completion, and a sufficient amount of time to pass under the final determinations prior to assessing whether a drastic and costly change to the existing scheduling process (pre dispatch) is required.

ESB proposed solutions

Unit Commitment for Security

Option 1 describes the Unit Commitment Security (UCS), "as a system analysis and optimisation tool" that will "identify any shortfalls and an inter-temporal *optimisation-based unit commitment model* that can determine the optimal additional commitment to remedy any shortfalls", "and optimises across time constraints, location and cost".[45]

The language used in the Consultation Paper is confusing as to whether the UCS currently exists in one form or another. Stanwell requests that the ESB confirms if a tool currently exists and what its capabilities are, so a cost and benefit analysis can be completed on the extension of the UCS to all system services.

Stanwell supports the implementation of an analysis tool but would like further detail as to the type of data and information that will be input into the tool, and to what degree the outputs will be shared with market participants. Information and data that is not commercially sensitive should be made available to participants in order to maximise the investability, innovation and operability within our market.

Prior to the implementation of a UCS, technical standards and a governance framework for ESS must be established. These standards and protocols will define how the UCS operates within the market and will enable participants to assess how existing plants capability can be improved to meet those standards.

[41] AER, Semi scheduled generators – Proposed rule changes. https://www.aer.gov.au/publications/reviews/semi-scheduled-generators-proposed-rule-changes
[42] AEMC, Wholesale Demand Response Mechanism. https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism
[43] AEMC, Distributed Energy Resources Integration Updating Regulatory Arrangements Consultation Paper, 30 July 2020, Proponents SA Power Networks, St Vincent de Paul Society Victoria and Total Environment Centre and Australian Council of Social Science. https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources
[44] AEMC, Generator registrations and connections, 8 October 2020. https://www.aemc.gov.au/rule-changes/generator-registration-thresholds
[45] ESB Post 2025 Market Design Consultation Paper, p 80

It will ultimately channel the design of new technologies and where investment in the market is made. Central to this being the ability of the UCS to identify "problem" regions and users of the system that are either contributing to the problem or a solution.

Stanwell expects that the work being completed by the AEMC System Service consultation process and the feedback provided by industry[46], will drive this process.

Ability to trade or procure system services

Option 2 aims to establish an ahead market to facilitate the trading and scheduling of system services, ahead of real time.

Stanwell supports the ESB undertaking extensive consultation with industry as to how system services should be valued and procured whilst maintaining the markets self-commitment nature.

The ESB has identified three potential alternatives for the procurement of system services under MDI-C: long term contracts, bid stacks and auctions. There is limited detail to how each of the procurement methods would work, however we acknowledge at a very high level each alternative has some merit.

Long-term contracts to a degree will provide assurance to market operators and Government and may help to shape operational and investment decisions. The utilisation of a bid-stack mechanism, like the current energy market model has some merit as it could leverage existing infrastructure and capabilities. However, it may be too complicated and costly.

Furthermore, if only a handful of participants are required to follow targets and comply with the rules the merit of this system will be compromised as it has been by semi-scheduled generators in the energy market. We note the AER's recent rule change request regarding semi-scheduled generator and dispatch instructions[47] aims to address some of these challenges in relation to large scale VRE. Stanwell will be making a submission on the AEMC consultation paper in support of this rule change once it is released.

Auctions offer a half-way point in that if they are designed correctly may be easier to use for new participants who solely want to provide ESS in either long-term or short-term markets.

If the ESB decides to further investigate Option 2, Stanwell would expect to see thorough analysis of hedging opportunities for the provision of ESS with bodies such as the Australian Financial Markets Association. The development of risk management mechanisms in the financial markets (being on the ASX and over the counter markets), to assess, manage and mitigate losses is essential to encouraging participants to enter a new market.

Integrated ahead mechanisms

Option 3 proposes ahead scheduling of energy and system services on a voluntary basis whereby commitment would be financial.

As discussed above, the pre-dispatch process of the energy market works efficiently as long as all market participants operate on a level playing field, meet technical and operational standards, are held accountable for their actions and provide AEMO with the same level of detail and accuracy no matter what type of market participant they are.

As highlighted by the Australian Energy Regulator (AER)[48], the treatment of semi-scheduled generation under the NER is outdated and must be updated to reflect the advanced capability of the technology and enable AEMO to more effectively manage the energy system. Semi-scheduled generators now have the technical, financial and compliance capability to participate in the NEM, as proven by their ability to rebid and adjust output in response to negative price dispatch intervals. They should be able to rebid and adjust output in accordance with dispatch instructions or other market signals that may be established in ESS markets.

[46] https://www.aemc.gov.au/rule-changes/synchronous-services-markets
[47] https://www.aemc.gov.au/rule-changes/semi-scheduled-generator-dispatch-obligations

[48] AER, Issues paper – Semi scheduled generator rule change(s) June 2020 https://www.aer.gov.au/system/files/For%20publishing%20-%20Issues%20paper%20-%20semi%20scheduled%20generator%20rule%20change%28s%29%20-%20Final.pdf p 13.

In addition to the AER's semi-scheduled rule change request, Stanwell acknowledges the work being undertaken by the AEMC on how to integrate energy storage systems into the NEM and the review of network service providers ability to control exports from households to the network. All three areas will have a significant impact on the ability of the market operators to manage the system and will lessen the degree of uncertainty and variability that the ESB has identified as being a key concern. Furthermore, once these areas are clarified it should allow for the development of additional avenues for distributed energy resources (DER).

The cost of dramatically departing from the existing energy framework must also be strongly considered. Customers, businesses and economies worldwide have been damaged by the COVID-19 pandemic. To implement a new, complex and costly framework that could be addressed through other low-cost means, cannot be justified to customers.

As identified in our response to the AEMC Consultation Paper on Short Term Forward Markets[49], we question if there are any benefits of AEMO establishing an additional platform for energy hedging. Several platforms already exist for participants to hedge long and short-term exposures via bilateral agreements, over the counter (OTC) brokered markets and futures (ASX 24). These markets are well established with robust existing governance, legal, commercial, financial, operational and professional guidelines.

Establishing a competing market would erode market liquidity, incur large development costs, burden market participants with dual regulatory requirements and higher resource allocation and ultimately would be a significant extension of AEMO's scope far beyond its existing organisational capability.

For the reasons outlined above, Stanwell does not support the extension of scheduling and ahead mechanisms to energy.

Compulsory ahead market design

Stanwell supports the ESB's position not to proceed with Option 4 requiring mandatory participation for all energy and system service resources.

Scheduling and Ahead Mechanisms conclusion

Stanwell welcomes further detail prior to progressing the implementation (or enhancement) of a Unit Commitment Security (UCS) analysis tool (Option 1) and supports the consideration of a range of procurement options for essential system services (Option 2), both with extensive stakeholder consultation.

Stanwell does not support the extension of scheduling and ahead mechanisms to the energy markets (Option 3) and supports the ESB's decision not to progress Option 4.

As Creative Energy Consulting (CEC) highlighted in its Scheduling and Ahead Market report, there are potential solutions within the existing NEM mechanisms;

> *"It might be feasible to value and pay new system services in dispatch, but only if these can be formulated in NEMDE constraint using a linear expression on either the LHS or RHS of the relevant security constraints"* [50].

Stanwell would like further consideration of the CEC's proposed solutions prior to committing to significant departure from the existing market design and prior to burdening customers with unjustifiable costs.

[49] Stanwell Corporation Limited, Short Term Forward Market Response to AEMC, May 2019. https://www.aemc.gov.au/sites/default/files/2019-05/Rule%20Change%20SubmissionERC0259%20-%20Stanwell%20Corporation%20-%2020190523.PDF

[50] Creative Energy Consulting, Scheduling and Ahead Markets Design Options for post-2025 NEM, June 2020, p 15-17.

Appendix E: Two-Sided Market, MDI-E

Increasing demand side visibility and participation

The ESB has identified that the relationship between consumers, network service providers and retailers is changing. The significant growth in distributed energy resources means that many consumers are now also generators. Changes in technology mean consumers' demand is also more flexible than it has been previously. As these changes are not visible in advance they are contributing to increased variability and uncertainty in the system.

The change in the relationship between consumers and other market participants creates opportunities to realise greater efficiencies but achieving these will require a number of challenges to be addressed. The development of a two-sided market will enable the potential large, valuable contribution of demand-side response to be captured, for the benefit of both consumers and the system overall.

Stanwell supports increased visibility of and participation by the demand side of the market. Increased information about the intentions and capability of load will aid AEMO to operate the market efficiently, which would be expected to benefit all consumers.

Stanwell does not consider the goal for a two-sided market should be full participation, particularly in the short-term. Further work is required to determine both actual household appetite and ability to participate and the expected net benefits of full participation versus the costs of implementing systems to allow this.

A staged roll-out of demand side participation will enable market bodies, participants and consumers to gauge the benefits to both consumers and the market, the costs and the appetite for continued expansion of a two-sided market. An initial focus on supporting and encouraging large energy users to participate will provide valuable insights for any potential future roll-out.

The interaction and interdependencies between the MDIs also need to be considered. As discussed earlier, more detailed development of the ESS MDI options will be required before the preferred design of any potential two-sided market design can be evaluated. What system services are to be procured and at what geographical granularity is a key input when considering the design of two-sided market/s. Conversely, the final design for a two-sided market should be determined prior to further development of transmission access reform. Failure to do so may result in a less efficient market design or the need for further disruptive changes to either or both MDIs to address these inefficiencies.

ESB analysis

In order to facilitate greater demand-side participation in the market, the ESB has identified that the outcomes any proposed reform would need to deliver:

- Provide choice and enable innovation: Ensure future arrangements can support the range of ways consumers may prefer to engage the market for energy services in the future;
- Ensure consumers are treated equitably: The energy market is run for the benefit of consumers. They should have opportunities to participate in the market if they choose to, but those who choose not to participate should not be disadvantaged;
- Create opportunities to lessen the 'energy divide': Ensure a two-sided market design can deliver benefits for users at the local network level; and,
- Provide incentives on third parties to partner with consumers: Reduce barriers for consumer participation in the market by encouraging third-party participants who can reward consumers for their participation and deliver increased demand response.

Stanwell supports these goals for any potential two-sided market reforms.

ESB proposed solutions

The ESB's proposed solutions are grouped under three key areas:

- Participation frameworks;
- Scheduling, pricing, dispatch and forecasting; and
- Consumer protections and complimentary measures.

Stanwell's feedback on each of these areas are discussed in turn below.

Participation frameworks

With its focus on consumer choice to participate in the market, Stanwell notes the ESB has softened its approach to two-sided market participation compared with the rule change from earlier this year, where it stated:

> *"[t]he full participation model should be the goal for a two-sided market as it would provide the most information to the market operator and elicit the most value from responsive capabilities in the market. However, consideration needs to be given to whether there should be a market-wide change at a given point, or some transition towards full participation."*[51]

With respect to the goal in the longer term to "transition to a market where any material quantities of supply or demand that are either price-responsive or variable would be actively involved in central dispatch", Stanwell would like clarification that "material quantities" refers to large, sophisticated energy users with load measured in MWh rather than households with loads measured in kWh.

If the ESB's intention is that this pertains to large loads, Stanwell suggests that the introduction of mandatory participation for loads that exceed a certain size, similar to the registration thresholds for generators, would make the AEMC's intentions explicit and provide certainty for consumers. The threshold should be set at a level above typical household usage, both to ensure loads too small to materially affect the market are not required to participate, while still giving smaller loads "choice and easy opportunities for consumers to engage where they choose to do so" either through on aggregator or on their own behalf.[52]

Similarly, Stanwell would like clarification that the ESB's goals are to remove barriers and support voluntary participation where there are expected net benefits for both those consumers choosing to participate in the market and the system overall. To this end, Stanwell maintains the position it advanced in its submission to the ESB's two-sided market Consultation Paper:

"Stanwell believes further exploration of the staged roll-out of demand side participation in a two-sided market is warranted. This would assist in determining both the pre-requisites for expanding participation from large users to smaller users (e.g. technology, tariffs, consumer protections), the expected benefits and costs associated with each stage of increased participation, and the appetite and barriers to entry for different types and sizes of consumers to participate in the wholesale market.

Stanwell suggests that most of the benefits of increased demand side participation would be realised through the selective participation model discussed briefly in the Consultation Paper. As the Consultation Paper notes, large energy users "represent around 66 per cent of overall demand in the NEM, but only make up 0.8 percent of total connection points in the NEM" (page 20). These sophisticated energy users have both the ability to shift energy use and the scale to impact the market when they do so. By comparison, while some individual residential households may have the incentive and ability to respond, kilowatt level changes will not be visible to the market operator unless significantly aggregated.

Scheduling large loads would significantly increase AEMO's visibility of the demand side at the transmission network level and avoid the potential negative impacts on the market of non-scheduled demand-side participation. Following successful implementation and evaluation of the selective model of participation, the further roll-out (i.e. increased net visibility at the meter, then full participation of the type detailed in the Consultation Paper) could be examined.

Moving to implementation and operation costs, the Consultation Paper notes "full participation model would likely be the costliest to implement, as an obligation to understand, and bid in intentions would apply to all participants".

Stanwell would like to see evidence or modelling that shows that the higher costs of full participation are more than offset by benefits for consumers. If this is not the case, Stanwell's position that greater net

[51] ESB, Moving to a two-sided market Consultation Paper, April 2020, p21
[52] ESB, Post 2025 Market Design Consultation Paper, September 2020, p 89

benefits would be realised at a lower level of participation merits an alternative approach to implementation."[53]

The consumption decisions of price-sensitive large load in response to wholesale price changes can significantly impact the network, particularly at the local level. Improved visibility of the intentions and price-responsiveness of large loads would aid AEMO in maintaining the network in a reliable, secure state.

With respect to households' appetite to participate in the market, Stanwell has previously stated:

> *"Further consideration of the appetite of households to participate in the market is also required. Stanwell contends that many households have limited appetite to participate in the wholesale electricity market. Households generally favour simple and hassle-free energy service where retailer [sic] manage their exposure to market fluctuations on their behalf and minimise the complexity of product offerings. This is evidenced by the high number of customers remaining on default offers, and low customer switching rates. We also contend that many customers have a limited ability to shift demand without a sizeable loss of utility*."[54]

Scheduling, pricing, dispatch and forecasting

Stanwell supports initiatives to increase the visibility and participation in central dispatch of load, particularly large loads. Removing barriers and incentivising traders to aggregate supply and demand to participate in dispatch on the same footing as generators (where feasible and appropriate) would be expected to increase the efficiency of the market.

The additional information about consumer preferences provided to the market operator and generators will ensure energy is not procured on behalf of those consumers (either by their retailer or through AEMO interventions in the market) at a price higher than the value they place on energy.

Stanwell also supports revising scheduling obligations and incentives that lower the barriers to currently non-scheduled participants becoming scheduled and encourage greater participation in central dispatch.

Stanwell would like to ensure sufficient attention is paid to the potential impact of the geographical spread of both the loads aggregated and the demand response provided on the efficient operation of a two-sided market. A balance needs to be struck between ensuring there are opportunities for interested consumers to participate in the market with ensuring their participation does not cause issues (e.g. local security issues at their node/connection point from changes in load in response to wholesale price) that outweigh the benefits of their participation.

Consumer protections

Stanwell considers it vital that adequate consumer protections are in place for both consumers who choose to participate in the market and consumers who choose not to.

There will also need to be protections against the potential distributional impacts of a two-sided market, particularly at higher levels of participation. As Stanwell noted in its two-sided market submission:

> *"Low income households may be unable to afford electricity at times when high income households are willing to pay more. Further investigation of the distributional impacts and mechanisms to ensure low income households are not excluded from an essential service will be required as part of future iterations of the proposed two-sided market."*[55]

These protections will need to ensure consumers who are able, but choose not to participate in a two-sided market are not disadvantaged because of this choice.

[53] Stanwell response to Consultation on Two Sided Markets, May 2020, pp 2-3
[54] Stanwell response to Consultation on Two Sided Markets, May 2020, p 3
[55] Stanwell response to Consultation on Two Sided Markets, May 2020, p 3

Two-Sided Market conclusion

Stanwell supports reform that will enable increased demand side participation in the NEM, but considers the goal of full participation, particularly in the short term, is not appropriate. Stanwell considers that an initial focus on supporting and encouraging large energy users to participate will provide valuable insights for any potential future roll-out to smaller customer.

Stanwell is concerned about the level of integration of two-sided markets with the other MDIs, particularly the interactions with the proposed transmission access reform. At the transmission network level, the implementation of a two-sided market would necessitate a redesign of the current transmission access reform proposal. The final design for a two-sided market should be determined prior to further development of transmission access reform. Failure to do so may result in either a sub-optimal overall market design or the need for additional changes to one or both MDIs.

There are also concerns about the interaction between two-sided markets and other recent rule changes. As Stanwell detailed in its two-sided market submission:

> *"At the pricing and risk management level there is a question relating to what incentives are trying to be imposed on the market. The Retailer Reliability Obligation (RRO) aims to incentivise appropriate and timely new entry by encouraging retailers to purchase hedges on behalf of consumers. On the other hand, the Demand Response Mechanism (DRM) appears to encourage consumers and their representatives to take and manage spot exposure. Without a clear intent as to what outcomes regulation is attempting to drive it is extremely difficult to define what success will look like, let alone measure it."*[56]

Further work is required to finalise the proposed two-sided market reforms, determine which provide net benefit on their own merits, and analyse the interactions with other MDIs and recent rule changes to ensure no unintended consequences or inconsistent signals to consumers and market participants, both within this MDI and across the MDIs.

Finally, Stanwell considers it essential that adequate consumer protections are developed and implemented for both consumers who choose to participate in the market and consumers who choose not to.

Stanwell looks forward to engaging with the ESB on the continued development of the proposed two-sided market reforms.

[56] Stanwell response to Consultation on Two Sided Markets, May 2020, p 2

Appendix F: Value Demand Flexibility and Integrating DER, MDI-F

Stanwell agrees with AEMO's assessment that when consumer-owned devices are aggregated and operated together at scale the potential is significant not only for the consumer but to contribute to the reliability and operability of the energy system[57], as described in the resource adequacy mechanism and scheduling and ahead mechanisms sections of this submission. To date the unfettered growth in DER has been poorly managed, affecting the operation of both the network and other generators.

High instantaneous penetration of variable renewable energy can affect AEMO's ability to maintain power system security. Minimising the impact of the existing, largely uncontrolled DER fleet and ensuring future DER roll-out does not adversely affect the security and reliability of the network is paramount.

ESB analysis

It is not clear from the ESB Consultation Paper, nor the KPMG/ITP Final Report – DER Integration and recommendation and issues, nor the AEMO DER work program, what the forecasted rate of DER uptake is expected to be. For example:

- The ESB Consultation Paper states that, "AEMO expects approximately 50% of consumers in the NEM to use some form of DER" by 2030, referencing no particular section, page or appendix in the AEMO 2020 ISP;
- The KPMG/ITP Final Report – DER Integration Recommendations and Issues presentation paper notes "based on AEMO projections, only around 8% will be by 2030"[58]. No references are provided for this observation; and
- The 2020 ISP states, "AEMO projects that DER could provide up to 13% to 22% of total underlying annual NEM energy consumption by the end of the outlook period"[59].

This wide range of expected DER update forecasts and projections will need to be compared with the technical limits of the system to accommodate additional DER, to ensure the proposed DER integration mechanisms do not aim to deliver more than is physically possible.

Stanwell does not refute that DER is expected to be a serious contributor to the shape of the market moving forward and welcomes the new opportunities that DER can offer to all stakeholders. However, we are concerned about the haste at which assumptions are being made about the future without considering more immediate issues.

The ESB's proposed initiatives do not appear to address the primary challenge of the impact of the existing sizeable DER fleet on reliability and security because of lack of visibility, let alone controllability. As stated in our 2019 submission to the ESB,

> *"The most important challenge related to the integration of DER into the electricity market is the ability to continue to operate the power system reliably, securely and efficiently with large installations that are not controllable…*
>
> *Stanwell is not opposed to optimising the value of DER and agrees that they can participate within the wholesale market on equal basis. However, the NEM already has a significant penetration of DER that can provide challenges operationally (at both the local and system level)."*[60]

Only once this issue has been addressed should the broader issue of further DER integration and ensuring DER is appropriately valued be pursued.

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[57] AEMO, Distributed Energy Resources Program, https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program

[58] ITP Renewables, Implications of Distributed Energy Resources for the post-2025 market design project. MDI Focus Group meeting. Tues 21 July 2020, slide 14, https://esb-post2025-market-design.aemc.gov.au/32572/1601011220-200728-p2025-der-integration-2-open-mic-session.pdf

[59] AEMO, 2020 Integrated System Plan, p 41

[60] Stanwell Corporation Limited, 2019 ESB Post 2020 Market Design, Response to Issues Paper September 2019, p 12 http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/Stanwell%20Response%20to%20Post%202025%20Market%20Design%20Issues%20Paper.pdf

ESB proposed solutions

In the next phase of the project, the ESB proposed focussing on development of a detailed DER integration proposal. To inform the development of this proposal, the ESB has asked what the most important priorities for DER market integration are. Stanwell's key priorities are detailed below.

Valuing DER

The current mechanisms for valuing DER do not provide appropriate signals and are unsustainable. As Stanwell has detailed previously:

> *"The risk of a small group of consumers benefiting from DER at the expense of overall system efficiency already exists. Consumers with rooftop solar derive value from their installation while it creates an overall system cost through local are[a] network requirements, inability for networks and AEMO to control their dispatch and the need to consider more conservative operational margins."*[61]

The ESB envisages the growth in DER will be driven by new technologies, new business models and increasing diversity of consumer expectations resulting in a diverse range of services, exacerbating the issue of inappropriate signals.

Stanwell suggests the value assigned to DER should be commensurate with the benefit they deliver. Any proposed mechanism/s need to provide signals that reflect the physical needs of the system at the time such services are delivered.

Net benefits of proposals

More broadly, the costs and benefits to both consumers and the system of each proposed mechanism will need to be considered, as well as the expected net benefit of the range of proposed mechanisms.

The potential value of DER integration needs to be weighed against the significant costs of DER integration, including the potential increase in consumer risk and the sizeable cost of the technology required for DER controllability and interfacing with the network, as well as the technical limitations of the network that could limit both DER participation and the costs imposed on other participants of increased DER participation.

To that end, Stanwell would like clarification that providing "opportunities for DER to participate in all markets where technically feasible and efficient to do so" will include a cost-benefit analysis to ensure an expected net benefit of DER integration into markets.[62]

As part of the Open Energy Networks Project, Energy Networks Australia engaged Baringa Partners to deliver cost-benefit analyses of four DER integration frameworks under two DER deployment forecasts. Their analysis found net benefits of DER integration under the high DER uptake scenario of approximately $3 billion to 2039. However:

> *"…under the lower DER uptake central scenario, implementing full functionality of any of the four frameworks would lead to negative net benefits. This suggests that while there remains uncertainty about the scale of DER uptake, the new functionality (and its associated cost) required to integrate DER should be implemented in an incremental way."*[63]

[61] Stanwell, 2019 ESB Post 2020 Market Design, Response to Issues Paper September 2019, p 10

[62] ESB, Post 2025 Market Design Consultation Paper, Sept 2020, p 99

[63] Energy Networks Australia, Open Energy Networks Projects position paper, p 33

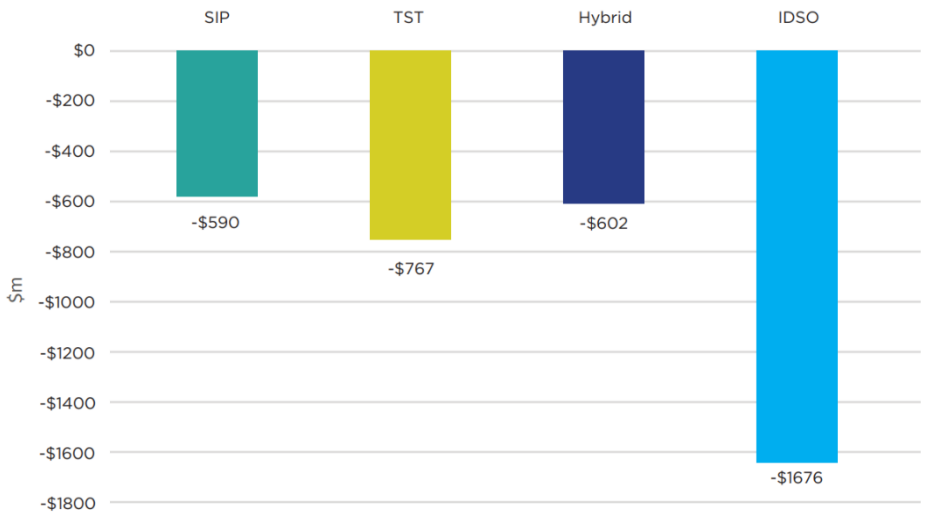

Figure 3: Overall net benefits under the Central scenario ($m, NPV 2019/20 prices) Source: Energy Networks Australia, Open Energy Networks Projects position paper, p26

Consumer appetite to participate

As discussed in the two sided market section at Appendix E, further analysis of the appetite of consumers with DER to participate in the market is required, to ensure consumers are not paying for mechanisms that are either not used or are not used to a level that results in a net benefit to the market.

As Stanwell has discussed in a previous submission, not all consumers with DER will participate in any market developed to support increased DER integration:

> *"Realistically, there will be three broad categories of consumers with DER:*
>
> - *Those that are completely passive;*
> - *Those that actively manage their devices for their own benefit, but everything is behind the meter (including third-party energy management); and*
> - *Those that participate in local or wholesale service provision via an aggregator."*[64]

The ESB needs to ensure the mechanisms developed are aligned with the expected level of both DER uptake and consumer appetite to participate in DER integration mechanisms.

Technology neutral

Attempting to realise the potential benefits of greater DER integration should not come at the cost of other forms of generation. The ESB Consultation Paper poses the question as to whether equivalent performance obligations that exist on large generating plant also apply at the individual DER level? Stanwell maintains equivalent obligations should apply where feasible; the same level of risk exposure and performance obligations should apply across all participants. Aggregators of DER should have similar performance monitoring and verification requirements, as well as the same level of wholesale market risk exposure.[65]

Stanwell appreciates that the ESB is concerned that if the obligations are too onerous or costly, DER participants may not integrate into the market. Stanwell suggests that as long as the obligations are reasonable (i.e. reflect the value of DER to the system) and transparent, they will form an important part of the cost-benefit analysis of DER integration. Instances where DER integration does not occur will be a reflection that there isn't an expected net benefit to the consumer with DER rather than a reflection that the obligations are too onerous.

Technology neutrality also needs to extend to revenues. The ESB note that "for aggregators to maximise the value of their DER portfolio, they need to access multiple revenue streams across multiple markets – known as value stacking".[66] This is in stark contrast to the current obligations placed on synchronous generators to provide uncompensated mandatory primary frequency response. Given the transformation of the market underway, Stawell suggests all generators, not just DER, should be permitted to access multiple revenue streams to maximise the value of the services they provide to the market.

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[64] Stanwell, 2019 ESB Post 2020 Market Design, Response to Issues Paper, September 2019, p 12
[65] Stanwell, 2019 ESB Post 2020 Market Design, Response to Issues Paper, September 2019, p 14
[66] ESB, Post 2025 Market Design Consultation Paper, Sept 2020, p 103

Demand Flexibility and Integrating DER conclusion

Stanwell is not opposed to optimising the value of DER by participating in the wholesale market on equal basis where feasible. However, the primary objective for DER integration in the short-term should be on mitigating the current technical challenges stemming from the current fleet of uncontrollable DER. Once this challenge has been addressed, identifying opportunities to optimise the value of DER through service provision can be realised in the long term.

Appendix G: Transmission Access and the Coordination of Generation and Transmission, MDI-G

Stanwell does not support the continued development or implementation of transmission access reform at this time. The significant changes between iterations of the proposed reform indicates that the AEMC is not converging on a robust final design for consultation and implementation.

Over the iterations of the proposed access reform, the AEMC has put forward a range of issues the proposed reform purports to address, including transmission network congestion, decreasing marginal loss factors, generator revenue uncertainty, lack of locational price signals and adverse operational incentives for generators and storage such as disorderly bidding. In its current state, the reform represents a costly, complex and disproportionate approach to achieving incremental gains in dispatch efficiency.

Stanwell contends that there are a number of no-regrets changes that could be implemented that would capture the bulk of the benefits of improved locational signals without the sizeable costs associated with transmission access reform implementation.

Current iteration of transmission access reform

The proposed reform continues to lack a clear purpose and demonstrable marginal benefits. The problems transmission access reform purports to address are not expected to improve under the current iteration:

- Investor certainty and cost of capital will not be improved by 3 month Financial Transmission Rights (FTRs) available up to 10 years in advance;
- FTRs do not protect established generators from the inefficient locational decisions of new entrants;
- Race-to-the-floor bidding will not be eliminated;
- Dynamic loss factors will continue to reflect the physics of generation located on congested parts of the network far from major load centres;
- Generator revenue certainty is expected to worsen, as even generators holding FTRs are potentially exposed to price risk and volume risk; and
- Contract market liquidity is expected to decrease due to the introduction of nodal and regional pricing, reducing retail competition and increasing retail prices for consumers.

Stanwell has significant concerns with the analysis of estimated implementation costs and modelled benefits. HARD software's estimated IT implementation costs appear to vastly understate implementation costs of both the Australian Energy Market Operator (AEMO) and market participants. Stanwell suggests it would have been preferable for the AEMC to compare HARD software's estimates with IT implementation costs of contemporary significant market reforms (e.g. Five-Minute Settlement) and undertake a comprehensive survey of market participants before publishing estimates that understate implementation costs to the point of being misleading.

Stanwell has identified several issues with the modelling of potential benefits that may result in the analysis overstating the potential benefits of the proposed reform, including:

- **Assumptions:** The modelling incorrectly assumes incentives for race-to-the-floor bidding will be eliminated and efficient dispatch is achieved when plant is bid into the market at incurred costs (i.e. short-run marginal cost) rather than economic cost (i.e. long-run marginal cost).
- **New technologies:** Batteries and pumped storage hydro have not been included in the solve (rather calculated external to the model) and new entrant pumped hydro is geographically constrained to areas of existing hydro.
- **Locational decisions:** Under the no-reform case, neither the Integrated System Plan (ISP) and Renewable Energy Zones (REZs) nor the available locational signals steer investment away from congested parts of the network.
- **Analysis:** Downplays instances where the results indicate the reform will deliver low or negligible benefits (e.g. includes more than $1.8 billion in benefits stemming from competition that may not materialise) and factors that could result in the modelled benefits exceeding the benefits that could be realised in practice (e.g. includes more than $1.7

billion in benefits from not investing in congested parts of the network while conceding generator investors would probably not invest in congested parts of the network anyway).

While transmission access reform is not warranted in relation to energy alone, it may be warranted if the ESB redesigns the NEM for co-optimised markets and those other markets benefit from granular locational signals. Further investigation into Locational Marginal Prices (LMPs) at that time in order to determine the expected marginal net benefits of their introduction would be justified. However, there would still be significant challenges that would need to be addressed, such as how AEMO would co-optimise the procurement of regional services (e.g. FCAS, inertia, operating reserves) against local services (e.g. energy, system strength).

Interaction with other Market Design Initiatives

Interactions between the current iteration of transmission access reform and the other Energy Security Board's (ESB) Market Design Initiatives (MDIs) cannot be determined as the other MDIs are still in their options phase.

Stanwell questions the alignment between the market redesign task set for the ESB and the process and progress of the project to date. As detailed in the ESB's scope and forward work plan:

> *"The COAG Energy Council has tasked the Energy Security Board with developing advice on a long-term, fit-for-purpose market framework to support reliability that could apply from the mid-2020s. By the end of 2020, the ESB needs to recommend any changes to the existing market design or recommend an alternative market design to enable the provision of the full range of services to customers necessary to deliver a secure, reliable and lower emissions electricity system at least-cost. Any changes to the existing design or recommendation to adopt a new market design would need to satisfy the National Electricity Objective."*[67]

The lack of firm recommendations and detail about options within the other MDIs and the tight deadline for design options to be released for consultation mean the ESB will not be able to deliver a long-term, fit-for-purpose market framework that demonstrably satisfies the National Electricity Objective. While options are still being developed, participants are unable to determine the expected net benefits of each option individually or the outcomes of interactions between the potential combinations of various options under each MDI.

Stanwell is concerned that advancing access reform while other MDIs are still in the option phase means the range of reforms cannot be assessed as a complete package. The implementation of the proposed transmission access reform could preclude other options from being implemented, potentially resulting in a less efficient market design or the need for further disruptive changes to address these inefficiencies.

No-regrets actions

There are a number of locational signals for investors currently, but these are blunt (e.g. current congestion) and some are not visible until deep into the investment decision process (e.g. "do no harm" provisions) or even after final investment decision (e.g. annual adjustments to Marginal Loss Factors). While greater attention is now being paid to the location of new investment on the network, additional ex-ante investment signals are needed to better guide investment location decisions to minimise the impacts on congestion and inefficient investment decisions. Transmission access reform is one of number of options to improve locational signals.

Over the course of recent reviews of transmission access, the AEMC appear to have dismissed potential alternative options to address the perceived issues with current access arrangements or deliver the claimed benefits of improved locational signals under the proposed access arrangements.

Stanwell contends that the majority of the benefits of better locational signals to inform investment decisions can be achieved without the cost and increased complexity of the proposed significant changes to the market design. To this end, there are several no-regrets actions can be implemented - the majority at little to no incremental cost - to improve locational signals ahead of investment decisions, including:

- Publishing all locational information currently produced by NEMDE to provide an immediate signal to potential projects.

[67] ESB, Post 2025 Market Design – Scope and Forward Work Plan, p 1

- Redeveloping the National Electricity Market Dispatch Engine (likely to be required for the implementation of the South Australia-New South Wales interconnector) to incorporate locational load, reduce model-induced inefficiency and increase locational signals for publication.

- Proactive publishing of indicative 'do no harm' requirements across the network to ensure new entrants are aware of and are required to mitigate the impact of their entry on established generators and the network more broadly.

- Producing network congestion maps to show potential participants the areas of the transmission network where there is currently sufficient network capacity for additional generation capacity to be added. Transgrid has previously produced maps showing expected congestion at times of high demand if committed projects proceed (refer Figure 4).

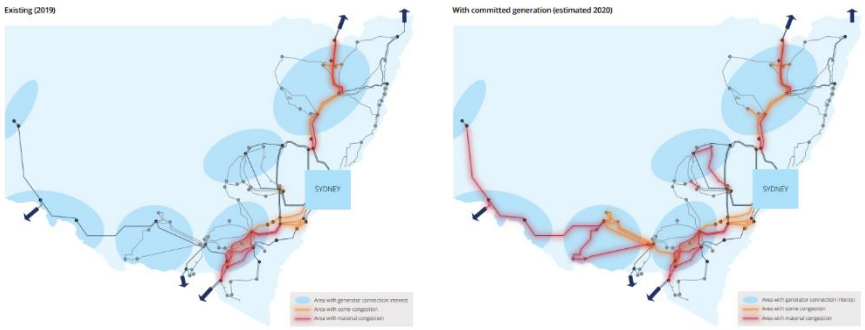

Figure 4: Congestion at times of high electricity demand. Source: Transgrid, Transmission Annual Planning Report 2019, p 7.

Transmission Access and the Coordination of Generation and Transmission conclusion

Stanwell does not support the continued development or implementation of transmission access reform at this time.

The proposed reform is an overly complex solution to a loosely and at-best generally defined problem. It has not been demonstrated that transmission access reform is needed, or the proposed reform is the best way of delivering the purported benefits. The AEMC has focussed on producing numerous iterations of transmission access reform, both in the current review and previous reviews, rather than identifying and assessing other potential ways to address the identified concerns with the current access arrangements or deliver the purported benefits of the proposed transmission access reform.

Stanwell also has significant concerns with the analysis of estimated implementation costs and modelled benefits. HARD software's estimated IT implementation costs appear to vastly understate implementation costs of both the Australian Energy Market Operator (AEMO) and market participants, and NERA's modelling and analysis of the results overstate the potential benefits of the reform.

Stanwell maintains the bulk of the benefits of locational signals can be achieved without the increased complexity and cost of the proposed changes to the market design. There are several no-regrets actions can be implemented at a small fraction of the most likely cost of the AEMC model, to improve locational signals ahead of investment decisions (e.g. redevelopment of the dispatch engine, producing network congestion maps, indicative "do no harm" requirements across the network) to dissuade generators from building in congested parts of the network.

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