Post 2025 Market Design

Response to the Energy Security Board's Post 2025 Market Design Options Paper

9 June 2021

Energy Networks Australia

Contents

Key messages

Essential System Services

- ENA supports initiatives that aim to reduce total costs for customers. While ENA appreciates the Energy Security Board's (ESB's) preference for unbundling services, in practice this approach must be tested to ensure that the benefits of reform materially outweigh the costs.
- The annual costs of providing system strength services may be material and unpredictable, as the Australian Energy Market Operator (AEMO) responds to real-time operational issues. The cost recovery arrangements should ensure that TNSPs are not exposed to significant cashflow issues arising from exposure to market costs and uncertain dispatch of resources.

Integration of DER and Demand Side Participation

- DNSPs are innovating to prepare for our future role in the energy value chain by developing the DSO Vision, tariff reform, technological advancements and co-design with industry, while simultaneously meeting the needs of customers today.
- ENA supports the intent of the Maturity Plan, but believes there is further work needed to address the long-term framework of governance and operation of the process.
- It is essential we do not repeat the mistake of policies such as power of choice reforms that assumed that competition and markets will always deliver benefits to customers. The benefits of proposed reforms with complex rules and arrangements that require significant active customer participation must be assessed based on likely real-world customer behaviour, not theoretical assumptions of high customer engagement.
- To support transformation and innovation the ESB should recommend Dynamic Operating Envelopes and Interoperability standards (IEEE 2030.5) as key technologies to progress.

Transmission and Access

- It is critical that access reforms are justified in terms of their expected net benefits, noting that generator locational decisions will already be strongly influenced by jurisdictional REZ planning arrangements and other government policies.
- ENA strongly supports the timely delivery of transmission projects that are in the long-term interests of consumers.
- Effective stakeholder engagement and the application of a rigorous cost benefit assessment are essential through the ISP development process and at an individual project level to support transparent investment decision-making.
- ENA favours streamlining the feedback loop following the ISP and RIT-T processes where this delivers a better outcome for customers
- ENA considers the hybrid connection fee and congestion management model identified by the ESB has merit and should be explored further, provided it can be implemented in a nationally consistent manner.

1 Overview

Energy Networks Australia appreciates the opportunity to provide a response to the Energy Security Board's Consultation Paper on the Post 2025 Market Design.[1]

Energy Networks Australia (ENA) is the national industry body representing Australia's electricity transmission and distribution and gas distribution networks. Our members provide more than 16 million electricity and gas connections to almost every home and business across Australia.

Consistent with the National Electricity Objective, ENA supports market design reforms that promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers. This requires the reform proposals to demonstrate that their benefits sufficiently outweigh their costs.

ENA believes that enhanced coordination between state and federal Government policies and NEM-led approaches is essential to deliver efficient cost-effective outcomes for customers in the long-term.

The unbundling of Essential System Services (ESS) must be tested to ensure that the benefits of reform sufficiently outweigh the costs. While ENA supports the development of arrangements to promote the efficient provision of system strength services, the design of supporting procurement and scheduling arrangements will need to be tailored so that the net benefits to customers are maximised.

ENA recognises that DER continues to be deployed at rapid rates. DNSPs are enthusiastically embracing the opportunity to effectively integrate customer DER into their networks, using innovation solutions, such as dynamic tariffs, community batteries, virtual power plants and dynamic connection arrangements. Some of these solutions already allow customers with DER to accrue benefits as well as ensuring the benefits are shared with those without DER. It is critical that customers, rather than traders, are placed at the heart of any reforms, since customers have their own motivations for investment in DER. The proposed reforms for multiple traders and scheduling are complicated and if they require active participation from a majority of customers it is unlikely they will deliver net benefits to all customers.

ENA supports the ESB's focus on promoting coordination of investment between network and generation assets to deliver least-cost outcomes at a system level. By providing accessible information to customers and stakeholders, market bodies, networks and other market participants can reinforce the efficacy of reforms in lowering overall costs to customers.

ENA notes that several reform proposals in ESB's Options Paper, particularly those considered longer-term reforms, are at the conceptual stage of development. ENA would welcome the opportunity to work with the ESB, market bodies and customer representatives to develop these proposals further before they are considered by Energy Ministers.

[1] Energy Security Board, Post 2025 Market Design Options Paper, 30 April 2021

2 Resource Adequacy and Aging Thermal Generator Retirement

Key messages

» A coordinated approach to Government policy is preferable to piecemeal Government intervention. In particular, ensuring better information provision both to and from governments to support enhanced integration of Government policies with existing infrastructure and market design.

2.1 Improved coordination

The ESB notes that a coordinated approach to Government underwriting will ensure investment driven by Government is better integrated with existing market design. ENA believes that enhanced coordination between Government policies, including underwriting and broader policies, and existing market design is likely to result in investment that is more appropriately targeted and will reduce the longer-term risk of asset underutilisation.

ENA supports market bodies providing additional advice to governments to inform the development of Government policies. Additional or improved information provision to governments will reduce the risk that policies are designed with imperfect information and consequently reduce the risk of unintended consequences for customers.

3 Essential System Services

Key messages

- The ESB's preference for unbundling Essential System Services (ESS) must be tested to ensure that the benefits of reform sufficiently outweigh the costs.
- ENA supports the development of arrangements to promote the efficient provision of system strength services. The design of supporting procurement and scheduling arrangements will need to be tailored so that the net benefits to customers are maximised.
- Cost recovery arrangements should ensure that TNSPs are not exposed to significant cashflow issues arising from exposure to market costs and uncertain dispatch of resources.
- The unbundling of Essential System Services raises regulatory design issues, particularly in relation to risk allocation and cost recovery arrangements. The AER's engagement on these issues will be valuable in ensuring that the framework is fit for purpose.
- ENA supports transparency in the use of contracted system services and AEMO's interventions in the market to maintain system strength. The costs of each service should be identified in the relevant timeframes and reported annually on a regional basis.
- The AEMC is well advanced in considering several Rule changes relating to ESS. ENA supports ESB's approach of allowing the AEMC to continue with these Rule change processes while ensuring the AEMC considers the implications of the post 2025 options.

3.1 Delivering net benefits to customers

The Options Paper provides a clear explanation of the drivers for change for the Essential System Services (ESS) of frequency control, inertia, system strength, and ramping capabilities/operating reserves. The increasing penetration of solar and wind generation, coupled with the exit of large synchronous plant, is creating challenges in maintaining the security and stability of the grid. As a result, the historical approach of ESS being provided as a by-product of energy generation is unsustainable.

ENA supports an approach of developing arrangements that promote the efficient provision of ESS for the benefit of customers; however, it does not accept that this requires moving progressively towards spot markets in all cases[2]. Instead, the objective of new arrangements should be to deliver lower costs for customers overall and maximise net customer benefits.

The question of costs and benefits is particularly relevant to the ESB's discussion of system strength services. The Options Paper explains that an optimal approach to procuring system strength services is likely to be achieved by:

- TNSPs contracting for system strength services to meet an investment timeframe; and
- AEMO procuring and scheduling system strength services to meet operational timeframes.

In principle, ENA agrees that AEMO's optimisation task would be greatly assisted by scheduling and procurement tools that determine how best to combine the available services under contract to TNSPs and the operational services that may be procured by AEMO. This complex optimisation problem must be

[2] Energy Security Board, Post 2025 Market Design Options – A paper for consultation Part A, 30 April 2021, page 43

managed in an operational timeframe by calling on services that meet system requirements at the lowest total cost. To enable this optimisation, AEMO would need to obtain contractual information from TNSPs in a form specified by AEMO, which may involve agreeing the technical specifications of the services to be procured.

In practice, the cost of developing and implementing the 'ideal' systems and processes may not offer the greatest net benefit for customers. ENA therefore encourages the ESB and market bodies to take a practical approach, having regard to the costs of implementing the systems and processes. As such, it is important that the procurement and scheduling arrangements are appropriately specified, given the potential benefits from co-optimising ESS alongside electricity dispatch.

3.2 Cost recovery, efficiency and transparency

For system strength services, AEMO's scheduling and procurement decisions will have implications for the costs incurred by TNSPs and the network charges paid by distributors and other directly connected customers.

ENA considers there may be significant cashflow issues for TNSPs if system strength costs become highly volatile, driven by AEMO's operational decisions to direct service providers who are contracted to TNSPs. The costs of providing system strength services should therefore lie with the party best able to manage the risk.

In addition, cost recovery arrangements should not expose TNSPs to unnecessary mismatches between annual revenues and costs due to timing delays. Existing network support cost pass-through arrangements for example operate two years in arrears and create significant cash flow risks, while inertia shortfall event and fault level shortfall event pass through arrangements are designed to operate on a forward-looking basis.

Where ESS are prescribed services provided by TNSPs, such as system strength, this raises regulatory design issues, particularly in relation to risk allocation and cost recovery arrangements. The AER's engagement on these issues will be valuable in ensuring that the framework is fit for purpose from a regulatory perspective.

ENA also supports the provision of information to customers and other stakeholders to explain how optimisation of the ESS will lower total costs to customers. The unbundling of ESS is likely to change the current cost mix between energy, ancillary services and network services. Annual reporting of this information will assist customers and stakeholders in understanding the interplay between these elements and the efficacy of the new arrangements in reducing total costs to customers.

3.3 Process, timelines and 'next' reforms

ENA supports the Option Paper's approach of allowing the AEMC to progress the current Rule change requests in relation to frequency control and operating reserves, having regard to input from the ESB. ENA notes that frequency control is regarded as an 'immediate reform', while operating reserves is categorised as an 'initial reform', even though both are currently being progressed by the AEMC through Rule change requests. To assist stakeholders, it would be helpful to provide further information on the timelines for each stage of the reform pathway.

There is insufficient information available at this stage to enable ENA to offer unconditional support for the 'next' reforms for ESS. For example, the case for developing inertia spot markets needs to be established, having regard to regional issues and the likely costs and benefits of reform.

As the ‘next’ reforms are currently at the concept phase, ENA regards them as setting an overall direction for reform rather than constituting a firm plan. In providing its recommendations to Ministers, it would be helpful if the ESB clarified the status of the different reform initiatives, noting that ‘next reforms’ will typically be less certain to proceed than ‘immediate reforms’, for example.

4 Integration of DER and Demand Side Participation

Key messages

- When considering the case for reform, it is critical that we consider only the marginal cost and benefit achieved compared to what can be delivered through targeted improvements to the current framework. Many of the intended goals of the ESB's proposals are possible now without added cost and complexity.
- ENA and its members are continually innovating to prepare for the networks' future role in the energy value chain through the DSO Vision, tariff reform, technological advances and co-design with industry, while simultaneously meeting the needs of customers today.
- To support continued innovation the ESB should recommend progressing Dynamic Operating Envelopes and Interoperability (IEEE 2030.5) standards
- ENA supports the direction of the customer protections framework noting that it does not supersede the National Energy Customer Framework (NECF) and that there is further work to be done to understand impacts across the entire base of customers
- ENA supports the policy aim of promoting choice for customers, to drive an innovative and competitive market.
- The proposed models of flexible trading and scheduled-lite introduce significant complexity and costs for both customers and potential new traders that are likely to be counterproductive to delivering the intended aims of the proposals.
- DNSPs are innovating to prepare for our future role in the energy value chain by developing the DSO Vision, tariff reform, technological advancements and co-design with industry, while simultaneously meeting the needs of customers today.
- ENA supports the intent of the Maturity Plan, but believes there is further work needed to address the long-term framework of governance and operation of the process.
- It is essential we do not repeat the mistake of policies such as power of choice reforms that assumed that competition and markets will always deliver benefits to customers. The benefits of proposed reforms with complex rules and arrangements that require significant active customer participation must be assessed based on likely real-world customer behaviour, not theoretical assumptions of high customer engagement.
- To support transformation and innovation the ESB should recommend Dynamic Operating Envelopes and Interoperability standards (IEEE 2030.5) as key technologies to progress.

4.1 Introduction

Australian's have embraced new energy technologies, particularly rooftop solar PV, delivering benefits at home and in our communities. While the uptake solar PV dominates, batteries both behind and front of the meter are also starting to be deployed. Coupled with the electrification of transport, these distributed resources will further profoundly change how the system operates and how customers interact with the power system.

Increasing amounts of Distributed Energy Resources (DER) not only affect distribution networks locally but also impact the larger interconnected transmission system through local system strength issues minimum demand, lack of inertia etc. In the future, DNSPs, TNSPs, AEMO and other parties will need to cooperate in joint efforts to maintain overall system stability and resilience.

Distribution Network Service Providers (DNSPs) have a vital role in supporting a safe, reliable, distributed and low carbon electricity system. NSPs are actively involved in working together with customers and market bodies to co-develop current and future roles and responsibilities.

The ENA broadly supports many aspects of the Market Design Consultation Paper related to DER integration and demand side participation, such as the need to have a rigorous cost benefit framework by which to assess the impact of proposed reforms, a strong customer protections framework and the pathway to future iterative reform (the Maturity Plan).

DNSPs are uniquely placed within the energy value chain where they interact with both technical system-level considerations (with AEMO and TNSPs) and managing local low-voltage (LV) networks and customer-facing operations. As DER continue to be deployed in the distribution network there will be an increasing need for DNSPs to more dynamically interact with AEMO to ensure ongoing system stability, leveraging the DNSPs deep knowledge and operation of their local networks.

In particular, DNSPs have developed risk management tools that allows for decision making with limited data across millions of assets. ENA and DNSPs continue to foster a strong working relationship with AEMO and their relevant TNSPs. The increasingly critical role of the distribution network will necessitate the transition of DNSPs to Distribution System Operators (DSO).

4.2 The DSO Vision

To provide clarity on the role DNSPs and the distribution networks will have in the future, DNSPs across Australia have worked together to consider how their future role in the electricity industry will evolve. This has resulted in the Distribution System Operator (DSO) Vision (Figure 1). This vision has been tested with customers and modified on the basis of their feedback.

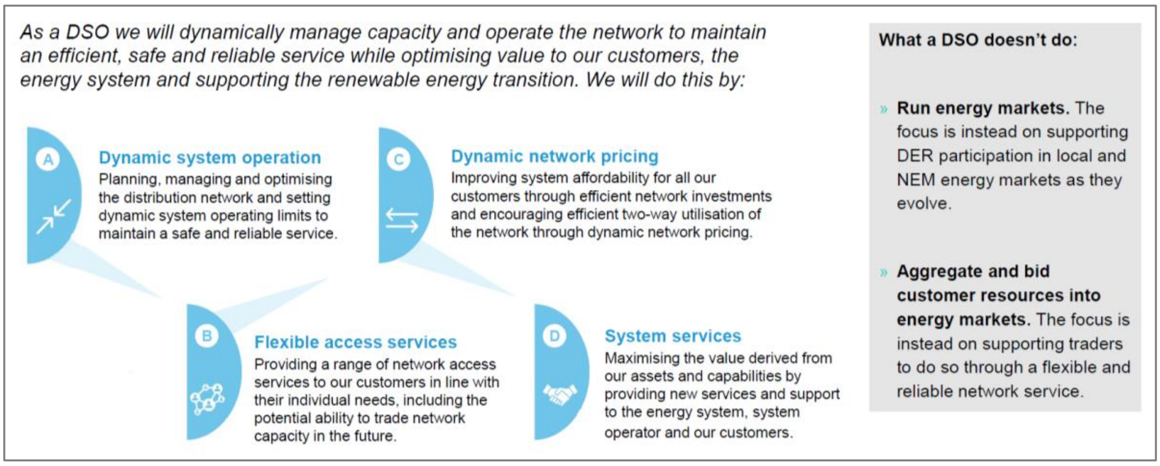

Figure 1: Australian DSO Vision

Fundamentally the role of a DNSP will remain to manage the physical capacity of local networks in a way that serves customers' best long-term interests. What is changing is the sophistication required to manage capacity more dynamically, and operate the network to maintain an efficient, safe and reliable service, while optimising value to our customers, the energy system and supporting the renewable energy transition.

The distribution network provides the interconnective tissue between buyers and sellers. To maintain reliability and support efficient market operation, networks need improved visibility and forecasting capabilities to not only estimate peak demand annually, but to identify capacity constraints across the network and across the day more dynamically.

- With this information in hand, the DSO aims to:
- get as much as possible from the existing network through encouraging network usage during off peak times and in parts of the network with spare capacity,
- actively manage network constraints (minimum and maximum demand) using a range of tools, including publishing DOEs, contracting with customers and solution providers for network support, and
- augment parts of the network to alleviate inefficient constraints when economically efficient to do so.

A level of congestion at peak times is part of an efficient network. Two key tools the DSO uses to manage the network and allocate network capacity between customers are dynamic operating envelopes and network pricing:

- Dynamic Operating Envelopes (DOEs): DOEs are essential to support the dynamic management of network capacity to ensure that capacity is optimised and support efficient and effective access to the local and distant markets and systems. A DOE provides customers and traders with information on how much electricity can be exported to and/or imported from the grid. DOEs aim to maximise the capacity available to customers while defining the limits that customers' DER must operate within for the safe and secure running of the network. Additional work on DOEs is being undertaken through ARENA DEIP[3].
- Network Pricing: Network pricing has a key role to play in the efficient allocation of network capacity by providing price signals on the costs of network use. Recent customer centric processes, such as the ARENA DEIP Access and Pricing review, have rapidly progressed the dialogue on network tariff reform. It is imperative that the ESB supports the reforms being proposed by the AEMC in their draft rule determination on access, pricing and incentives for distributed energy resources

These two things are starting to take shape in form of flexible network connection agreements with customers. Network connection arrangements need to provide choice to customers to meet their individual needs, including static fixed connection options or dynamic connection options shaped by DOEs. For example, a customer with a sizeable battery system may want firmer access and more capacity (that is, a larger operating envelope) to ensure they can provide services into the market during peak times, whereas a solar customer may be willing to be export limited during peak times in exchange for lower network charges.

DSOs across the country will also continue to play a role in supporting the stability of the end-to-end system. Much of this involves leveraging the capabilities DNSPs developed to traditionally manage network capacity, but with a broader system-wide objective in mind.

For example, DSOs can:

[3] https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/dynamic-operating-envelopes-workstream/

- use the same systems that provide dynamic operating envelopes to activate emergency shedding of load or generation when required by AEMO for system security during contingent events.
- dynamically configure the network, change the timing of direct load control programs and manage voltage to support AEMO with regional supply and demand balancing, and
- continue to enact directions from AEMO through existing and future capabilities.

By leveraging these capabilities, customers and communities across Australia can get the most value from the shared distribution networks that we have all invested in. It is also important that the industry is transparent with customers about the impacts on them from arrangements like the minimum demand backstop and technical standards. An increased level of transparency can be achieved through leveraging network capabilities that will be monitored and overseen by the AER.

More detail on the Vision can be found on the ENA website[4] and further materials will be released later this year.

4.3 Customer protections

ENA strongly supports the direction of the Consumer Protections – Risk Assessment Tool noting that it is not intended to supersede the existing National Energy Customer Framework (NECF) or any other existing jurisdictional or regulatory obligations.

To the extent that it overlaps with determining costs and benefits for other reforms being proposed, ENA also supports statements made on the "careful evaluation … to avoid over-regulation" and the need to consider "risks cause, effect and magnitude".

One key concern ENA has, is that customers who have opted out or are unable to participate may disproportionately end up bearing the costs that networks and other parties will incur to support other customers who opt-in to active market participation. Network cost recovery is generally socialised across all customers, potentially resulting in a cross-subsidy from those customers who will not receive the benefit of this service.

The AEMC's Access, Pricing and Incentives rule change[5] seeks to address this to a degree by creating a framework that would allow the costs associated with DER enablement to be allocated to DER customers, avoiding new cross-subsidies. Even with this rule change, costs incurred by other actors in the system in enacting reforms, e.g. AEMO or AEMC, may flow back to non-DER customers. The distribution of benefits and costs is therefore an important factor to consider when evaluating new reforms.

ENA emphasises the importance of co-creating these customer protection frameworks with customers to ensure that the protections meet and address customer needs. Customers should have the right to review and endorse the protections framework before it is implemented.

4.4 Maturity Plan

ENA also strongly supports the objectives of the proposed Maturity Plan. It is pleasing to see that the ESB does not propose to have a large number of reforms planned for immediate delivery but has instead chosen to flexibly prioritise the most urgent issues and delay others.

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[4] https://www.energynetworks.com.au/news/energy-insider/2021-energy-insider/aiming-for-dertopia-not-dystopia/

[5] https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources

The success of the Maturity Plan process will largely depend on the effectiveness of those responsible for delivering each phase of the plan. There are concerns that the current approach to exploring the management of minimum demand is extensively revisiting the prior 6-9 months of "sprints", without the necessary deep technical focus that is needed to genuinely produce a workable national approach to managing minimum demand. Minimum demand is a critical issue, as are all the proposed topics for the Maturity Plan, and without effective leadership for each specific topic, practical technical solutions will not be delivered.

Given the likely weight that will be assigned to the outcomes of the Maturity Plan process and recognising that the ESB has a finite life, it is critical that there is a robust governance framework for the process of the Maturity Plan and to assign responsibilities and manage its outcomes.

The transition from the ESB to an alternative responsible party needs to be urgently determined and agreed with stakeholders. ENA suggests that the Australian Energy Market Commission (AEMC) take the lead in establishing an appropriate system to manage this process. It is ENA's understanding that an interim steering committee for the Maturity Plan Pilot has been formed, but we would like to see more robust and transparent approach to the transition and to ensure longer-term arrangements are in place as soon as possible.

ENA note that the ESB has a rule change covering Governance of distributed energy resources technical standards[6] that is currently pending, this would potentially place the responsibility for overseeing the governance of DER technical standards with the AEMC. ENA believe that this could be an appropriate mechanism through which to progress the Maturity Plan.

ENA is ready to support the ESB through the Maturity Plan process on all issues relevant to networks.

4.5 Flexible trading arrangements

While ENA supports the intent of the ESB's ambition to foster increased competition and customer choice in the market, there is a concern that proposed models will instead introduce a significant level of complexity with marginal benefits to end customers.

Competition should not be the primary objective of the reforms, but rather delivering better outcomes for all customers. The original intent of earlier work was to support the participation of DER in markets, while the more recent work is very trader-centric, rather than customer-centric.

The ESB has attempted to design models that put most of the onus on customers who want to enter flexibility trading arrangements to reduce the cost impacts on other customers from system changes. However, it is not clear that the introduction of an additional layer of competition behind the meter, with an associated increase in cost and complexity, would ultimately lead to significant innovation and greater overall customer benefits. Instead, it may be more beneficial to review why the competitive retail market has not delivered the desired level of innovation to date. A key enabler of competition will be standards to support interoperability (e.g. IEEE2030.5) that reduce barriers to swap between traders and focusing on this may prove beneficial for a wider set of customers.

It is critical that the ESB engages with customers and their advocates to determine the extent to which there is a desire or demand for the choice to unbundle different elements of their electricity supply and demand through multiple traders.

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[6] https://www.aemc.gov.au/rule-changes/governance-distributed-energy-resources-technical-standards

The ENA acknowledges that there is a highly active segment of customers in the market who might participate, but in the long term they are likely to represent a small minority and may not be indicative of the wider customer base upon which costs are shared. It is essential we do not repeat the mistake of policies such as power of choice reforms that assumed that competition and markets will always deliver benefits to customers. The benefits of proposed reforms with complex rules and arrangements that require significant active customer participation must be assessed based on likely real-world customer behaviour, not theoretical assumptions of high customer engagement.

Another consideration is related to the customer protections framework mentioned earlier. If customers choose to opt into higher levels of participation, they may require significant physical changes to their home wiring that may be unique to a specific trader. This may make it difficult to subsequently churn away to other traders and instead lock them into their initial retail offer.

ENA also believes that future reforms should not always require a trader to manage customer DER. While some customers will embrace VPPs and other aggregation schemes, many may prefer to respond to time-of-use tariffs and/or optimise their solar self-consumption using their own smart appliances or home energy management systems. Network tariffs, such as solar sponge tariffs, coupled with time-varying retailer tariffs provide simple, effective, long-term signals and allow the value of supporting efficient utilisation of the network to be shared with customers, either directly or via a trader at least cost.

Customer DER already provides services to support secure and safe network operation through DNSP load control programs. These programs reward customers with a lower tariff for providing support to the DNSP and the benefits of these programs flow not only to those customers participating directly, but to all customers of that DNSP. It may be beneficial to consider how to utilise DNSP-managed load control that already exists.

As highlighted in Figure 1 *Australian DSO Vision*, DNSPs do not ultimately see it as their role to bid and dispatch customer resources into energy markets, however as a society we should leverage existing network assets and capabilities where possible. At a minimum, options should be considered to reschedule DNSP direct load control programs to better match solar output and reduce the need to call on other mechanisms to manage minimum demand.

A key principle of any reform to customer DER should be that it is in the long-term interests of all customers and that cost is not needlessly increased by introducing a set requirement for a market-led solution. Where a trader can offer a customer increased value, via a market, versus the value that can be secured through existing DNSP solutions, the customer is likely to pursue that increase value, but that may not be the best outcome for other customers. Pre-emptively transferring all existing direct load control to the competitive market is unlikely to lead to lower cost outcomes for all customers.

Regardless of various permutations for trading relationships that will develop over time, the system will always need to accommodate a spectrum of customer preferences, including those that do not wish to enter into new and complex commercial arrangements. DNSPs are committed to ensuring that DER customers who are not enrolled in aggregation schemes will still benefit from network improvements such as DOEs or other forms of dynamic export limits. The future framework needs to benefit and support all customers, whatever their level of participation and engagement.

Networks are currently working collaboratively with stakeholders through the ARENA DEIP process on a consistent design and framework for DOEs[7] at the customer connection point. Where a customer has multiple forms of DER managed by multiple traders, yet shares the same connection point, it is difficult to see how the available capacity is allocated amongst the various DER and traders.

It is also difficult to see how multiple price responsive traders will be exposed to cost reflective network tariffs, both import and export, that are a key part of incentivising efficient use of distribution networks and reducing costs for all.

The ENA encourages the ESB and others to consider targeted real-world testing of the reforms to give confidence that there is genuine customer demand, that benefits outweigh costs and that the benefits flow through to all end-customers. The ENA welcomes further engagement on this issue as it develops.

4.6 Connection point models

The concept of multiple traders has been explored before through the Multiple Trading Relationships (MTR, ERC0181)[8] and in 2016 the AEMC concluded that

> "*Implementing the proposed framework may deliver some cost savings to a small number of customers who seek to set up very specific MTR arrangements. However, it is unlikely to deliver cost savings to most customers seeking to engage with multiple retailers. It is therefore unlikely to materially reduce costs for customers generally, and so unlikely to drive demand for new energy service providers or stimulate service innovation and competition in the retail electricity market*." February 2016

ENA recognises that increased competition in the trader sector would likely be beneficial for some customers, but in 2016 the MTR models proposed (noting they were not the same as the ESB's current models) were assessed as not in the long-term interests of all customers.

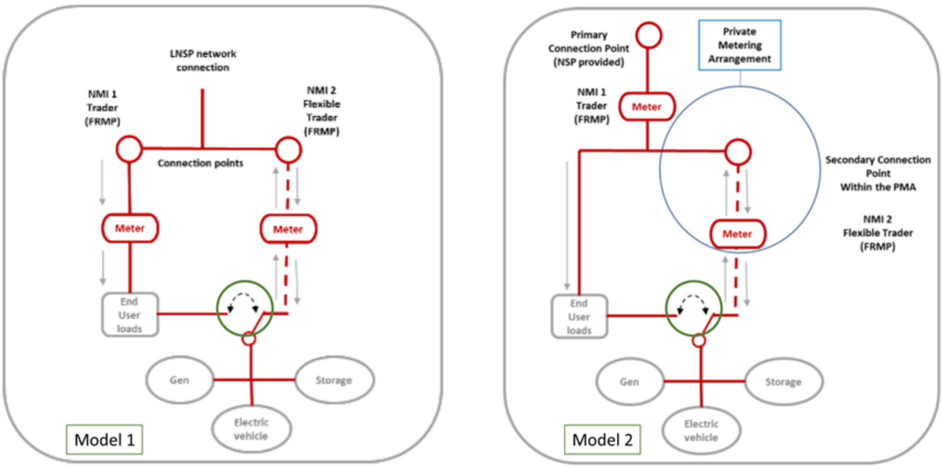

Figure 2: Models 1 and 2 showing the switch (ringed in green)

[7] https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/dynamic-operating-envelopes-workstream/

[8] https://www.aemc.gov.au/sites/default/files/content/d37688a5-d16d-442b-80f5-e7fa51d64ab7/Multiple-Trading-Relationships-Final-Rule-Determination.pdf

One clear difference between the earlier MTR models and the current models is the addition of a switch that appears to allow DER to operate via one or other connection/NMI. This switch allows a range of potential issues occur, the most serious of which is risk of electrocution (see figure 2).

AREA	***MODEL 1***	***MODEL 2***
Change from today	SGA Framework already exists, but needs modification to allow import and allow the provision of ancillary services	Minor (May leverage existing embedded network arrangement principles – only in some jurisdictions. See comments below)
Cost[9]	Significant (~$3200 + up to $500 pa) At a customer model level, we can expect the costs to be very high At an individual customer level, the customer will bear additional connection/meter installation and NMI establishment costs	Moderate (~$600) Expect the customer costs to be high but lower relative to the Model 1 option At an individual customer level, the customer will bear meter installation and NMI establishment costs, but not the additional connection point costs.
Complexity	High for customers that need to establish a second connection point and moderate for networks as it requires a review of the safety rules around second connection points	High for customers and moderate for networks
Metering	Additional meter required; Power of Choice may delay delivery	Additional meter/s required; Power of Choice may delay delivery
Customer type	Large (C&I); Current limited use for residential/domestic customers	Broader range of smaller commercial/residential customers
Safety	Switch between 2 connections increases the threat of electrocution (one connection may be de-energised, while other is not and switching (by a 3rd party trader) may result in electricity flowing into the grid from "de-energised" connection from exporting DER	Similar safety concerns to Model 1, but potentially more relevant to the local site. Switch (controlled by trader) may also result in electricity flowing in "de-energised" connections from exporting DER on assets behind the meter.
Disconnection	Complex with additional safety concerns for DNSPs For traders, the switch may allow a customer to continue on supply from the second trader	Simpler and safer for DNSPs For traders, disconnection at the secondary point, could be over-ridden by using the switch, allowing DER to participate via primary
Traders	Only 2: import and export/import	Many, potentially one per DER
Physical considerations	Space needed for additional NMI meters Potential need to rewire if trader changes Additional asset level NMI-compliant meters for each asset managed by a trader	Space needed for additional NMI meter Potential need to rewire if trader changes Additional asset level NMI-compliant meters for each asset managed by a trader
Charging DUoS	Each connection incurs DUoS	Potentially complex, potential split per trader/asset. However, DUoS could just be levied at the primary connection and traders would have to resolve
Dynamic Operating Envelopes	One per connection point (2). Could DER, via switch use the "import" only connection, so increasing the opportunity to export?	If by primary connection, only one DOE per connection. Potentially complex if separate traders for separate assets would need to determine capacity allocation amongst themselves.
Embedded Framework issues	No	Yes, in some jurisdictions
Likely customer uptake	Low, perhaps C&I who can better absorb large upfront costs	Low, cost and complexity
AS 3000	Illegal	?
DER Register	Currently each DER is assigned to a specific NMI, switch allows DER to move between NMIs	Currently each DER is assigned to a specific NMI, switch allows DER to move between NMIs or would all DER be assigned to the primary NMI?
Gaming	Possible	Unlikely
Other existing routes to participate	Yes	Yes

Table 1: Issues related to Models 1 and 2

[9] https://esb-post2025-market-design.aemc.gov.au/32572/1611022920-enegeia-expert-advice-on-the-cost-of-establishing-a-second-connection-point-v2.pdf

Both Models 1 and 2 proposed by the ESB are highly complex, do not facilitate simplicity for customers and are likely to be costly for customers to implement. Model 2 may be marginally preferable, but there are likely to be issues around implementation in some jurisdictions where embedded network arrangements may add further complexity. Similarly, Model 1 is already possible, but requires modification (rule changes) to support bi-directional flow and provision of ancillary services.

It should also be noted that the rollout of meters under the Power of Choice competitive model has been extremely slow and that both models 1 and 2 are dependent on additional meter installations. It is not clear how the current competitive metering delivery approach will facilitate a rapid implementation of either model, or any model that requires additional NMI-compliant meters.

ENA suggests that the ESB, DNSPs, customers and traders work together to develop an approach that is simple and cost-effective to deploy and leverages the existing successful VPP demonstrations[10].

4.7 Schedule-lite models

ENA believes that certain levels of increased DER visibility is important for both DNSPs (local distribution network) and AEMO (aggregate system activity), however further work must be done to ascertain the extent to which dispatchability benefits outweigh costs.

The VPP demonstrations have successfully shown how DER can deliver benefits to customers and deliver energy and ancillary services to AEMO without the complexity and cost of scheduling or complex connection models.

ENA suggests that where increased visibility of DER devices is warranted there are other monitoring approaches to NMI meters that can deliver operational awareness to system operators. It is not yet clear how centralised scheduling and control of customer devices, will deliver benefits to customers that will outweigh the direct and indirect set-up costs for customers and further evidence is required.

It is not immediately clear how ancillary service costs will be managed between trader and participating customers. While scheduled-lite may help a customer avoid ancillary service costs, presumably failure to meet a dispatch target will result in a penalty.

Customers will make decisions based on their own needs and choices and it is the role of DNSPs to provide or support the services they demand, like community batteries and markets, flexible export etc.

AEMO has indicated that the scheduling of aggregated small-scale DER, while desirable to deliver more accurate forecasting and visibility, brings significant cost and complexity to their operations and to customers that may well outweigh the benefits[11][12]:

> "*Determining how aggregated portfolios should participate in scheduling and dispatch and how existing or new NER obligations are to apply involves a significant body of work. This includes detailed solutions and cost benefit analyses to identify which real and emerging issues need to be addressed by the regulatory framework, and how market participants with aggregated connection points can most efficiently offer energy and services in the NEM to maximise consumer benefits*." February 2021

[10] https://arena.gov.au/assets/2021/05/advanced-vpp-grid-integration-final-report.pdf

[11] https://www.aemc.gov.au/sites/default/files/documents/a31._aemo.pdf

[12] https://www.aemc.gov.au/sites/default/files/documents/6._aemo_submission.pdf

ENA would be keen to further understand and help inform the cost/benefit analysis on the implementation of the proposed scheduling models. It is essential that that any scheduling approach continues to be a voluntary opt-in choice for customers.

4.8 Further considerations

In addition to the issues put forward by the ESB in options paper, the ENA believes that further consideration needs to be given to:

- Network and community resilience in the face of a changing climate,
- Community energy, including resource sharing and local markets, and
- Insights from customer research.

Maintaining a safe and reliable service has been challenged by the rising frequency of bushfires and extreme weather events and this has led to a renewed debate on the level of network and community resilience that is required. Supplying remote customers via standalone power systems (SAPS) is rapidly becoming a cost-effective answer in more places and, as recognised by the AER in their recent ring-fencing review, is an increasingly important tool in the network provider's toolbox.

In addition, further consideration should be given to a framework that allows for pro-active resilience planning with communities. This would also require a mechanism for networks to assess their assets and propose hardening programs for parts of the network servicing critical infrastructure such as water and telecommunications.

A consistent theme in conversations with consumer representatives has been the desire to enable community energy, which includes sharing and trading of community resources such as solar and community batteries and customer DER.

Conceptually this could be enabled through allowing local settlement of energy between customers that are connected to the same part of the distribution network. However, a lot of complexity exists in the practical implementation of these markets and solutions also need to accommodate for a mix of community members that want to participate in local sharing and those that prefer to receive their energy from the wholesale market in order to take advantage of the full breath of retail offers and incentives.

ENA recommends that a range of options is further explored in consultation with customers and the industry and potentially through the ARENA Distributed Energy Integration Program.

State and Local Governments are also starting to consider the role of DNSP-led community batteries that allows communities to share storage capacity and increases the solar hosting capacity of the network. A consistent NEM-wide framework that gets ahead of this and enables State Governments to enact these policy positions will be important.

All the reform programs being considered by the ESB would benefit from carefully considering what customer research in recent years has taught us about demand elasticity, customers' willingness to engage and the industry's (collective) social licence to control DER. We understand CSIRO's NEAR Program[13] will soon publish a survey of nearly 3,000 customers across Australia and this may contain informative perspectives on demand response and community energy.

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[13] https://near.csiro.au/

5 Transmission and Access

Key messages

- ENA strongly supports the timely delivery of transmission projects that are in the long-term interests of customers.
- Stakeholder engagement and the application of a rigorous cost-benefit assessment are essential through the ISP process and at an individual project level to support transparent investment decision making.
- Rigorous and transparent cost-benefit assessments should be required for all projects, including for actionable ISP projects, and remain focused on costs and benefits arising from the electricity sector, consistent with the National Electricity Objective.
- ENA favours streamlining the feedback loop following the ISP and RIT-T processes if this delivers a better outcome for customers.
- Transmission and access reforms must be justified in terms of their expected net benefits to customers, noting that generator locational decisions will already be strongly influenced by jurisdictional REZ planning arrangements and other government policies.
- ENA considers the hybrid connection fee and congestion management model identified by the ESB has merit and should be explored further, provided it can be delivered in a nationally consistent manner.

5.1 Reform pathway

The Options Paper highlights that several important reforms have either been completed or are being progressed in relation to the integration of transmission, generation and storage and improvements in congestion management. While there are challenging issues to be resolved, particularly in relation to the REZ framework and the Dedicated Connection Asset Rule change, these initiatives are intended to drive more efficient, lower cost outcomes for customers. On that basis, ENA supports the overall direction of the ESB's proposed transmission and access reform pathway.

ENA considers that the ESB's longer term vision of Locational Marginal Pricing (LMP) and Financial Transmission Rights (FTRs) will need a more comprehensive assessment, including of likely implementation costs, before it can be fully supported by stakeholders.

5.2 Investment and planning framework

A key recent reform is the implementation of the Actionable ISP Rules and publication of the accompanying AER RIT-T instrument and application guidelines[14], which explain how the RIT-T applies to actionable ISP projects. These Rules and guidelines followed extensive stakeholder consultation which considered, among other things, how the ISP and the RIT-T for actionable ISP projects would ensure only prudent and efficient projects proceed.

[14] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable

Despite the Rule change only being completed within the past 12 months, the Options Paper questions whether the RIT-T provides additional benefits for actionable ISP projects beyond the ISP and contingent project application (CPA) processes. The Options Paper also notes that the application of the RIT-T may lead to project delays, as it increases the time taken to obtain project approval.

ENA supports the ESB's view that barriers to the efficient delivery of actionable ISP projects should be removed but considers that appropriate planning and assessment processes must still be conducted to ensure transmission investments are prudent, efficient and in the long term interests of customers. For example, appropriate engagement with communities, including consideration of planning matters, should be undertaken by TNSPs even if it creates timing challenges for project delivery.

In contrast to the commentary in the Options Paper[15], ENA does not regard matters such as community concerns, biodiversity and indigenous heritage as obstacles to the timely delivery of transmission projects. Our members want to ensure transmission investment decisions take account of these issues as part of the planning and investment process, given the importance of establishing and maintaining long term, constructive relationships with the landholders and communities who will host transmission infrastructure over its multi-decade life. Maintaining these relationships over the asset life cycle is critical to networks' social licence to operate.

ENA also considers that a rigorous and transparent cost-benefit assessment should apply to all proposed transmission projects, including actionable ISP projects, to demonstrate they present prudent and efficient investments. This enables TNSPs' local expertise and network knowledge to be harnessed in developing options, including route selection and technology choices, to address identified needs. Consequently, the RIT-T process helps to clarify a number of aspects in the detailed optioneering of the project and test the value it is expected to deliver, which will ultimately lead to improved investment decisions to the benefit of customers.

While the continued application of rigorous and transparent cost-benefit assessments is supported, ENA recognises that the current ISP planning and investment framework, which includes a 'feedback loop' with AEMO, is complex and resource intensive. Recent experience indicates that timeframes for confirming with AEMO that a proposed project remains consistent with the optimal development path can take many months. In principle, ENA would support initiatives to streamline this process, if this can be achieved without compromising the objective of delivering the optimal project on behalf of customers.

5.3 Design of the RIT-T

The Options Paper notes that governments may value a broader range of benefits not currently captured by either the ISP or RIT-T frameworks and suggests these wider benefits could be captured in a broader cost benefit test to guide the respective contributions of taxpayers and electricity consumers[16]. ENA also notes that some jurisdictions are undertaking various initiatives in response to a RIT-T that they regard as not supporting strategic customer benefits or appropriate delivery timeframes. These jurisdiction-led initiatives provide important context for a further review of the RIT-T.

ENA acknowledges that the scope of transmission project assessments is a policy issue for Energy Ministers to determine but considers cost-benefit assessments should only take account of costs and benefits from the electricity sector, consistent with the National Electricity Objective. Such an approach

[15] Energy Security Board, Post 2025 Market Design Options – A paper for consultation Part A, 30 April 2021, page 78

[16] Ibid, page 79.

will "prevent electricity consumers paying for inefficient investment" and ensure electricity consumers only pay for investments if the benefits they receive exceed the costs they face[17].

It remains open to government to fund all or part of specific transmission investments. Under the current RIT-T framework, any direct government funding is treated as a benefit to electricity consumers. This was confirmed by the AER in its 2020 update to the RIT-T application guidelines and provides an avenue for broader benefits to society to be captured and funded by government[18].

The RIT-T has been the subject of independent reviews by the Productivity Commission and COAG Energy Council, both of which concluded the investment test should not be expanded to consider costs and benefits outside the electricity sector. A future review of the RIT-T should reconsider these findings in light of the recent jurisdictional developments, so that all parties have confidence in the cost-benefit test.

5.4 Medium term access reform options

ENA notes that the Options Paper provides significant new information on how access arrangements may transition from the interim REZ framework to a longer-term solution comprising LMP and FTRs. It offers medium term reform options that aim to improve incentives for efficient locational decisions and congestion management, while affording market participants some time to address challenges associated with moving to LMP and FTRs from the current arrangements. While ENA cannot provide unconditional support for implementing LMP and FTRs at this stage, it recognises the value in ensuring any interim reforms would not be inconsistent with a longer-term transition to LMP and FTRs.

The Options Paper describes five interim reform options:

(1) **Congestion management model**. This model would address disorderly bidding by imposing a congestion management charge on generators and provide a rebate on the basis of availability (not dispatch quantity).

(2) **Congestion management model modified for new generation and REZs**. This option modifies option 1 so that the rebate only applies to incumbent generators and new entrant generators that connect as part of a REZ tender process. Unlike option 1, this also provides locational signals to new generators.

(3) **Locational connection fee**. This option would provide locational signals by proposing a connection fee for new generators that varies by location.

(4) **Generator transmission use of system charges (G-TUOS)**. This would provide locational signals for generation connections, but require the development of a charging methodology and raise transitional issues for existing generators.

(5) **Hybrid connection fee and congestion management model**. This approach combines options 1 and 3, thereby providing both congestion management and locational signals.

ENA considers option 5 has merit and warrants further investigation, provided it can be implemented in a nationally consistent manner and accommodate REZ development initiatives being pursued by jurisdictions participating in the NEM.

[17] COAG Energy Council, Review of the Regulatory Investment Test for Transmission, 6 February 2017, page 34.

[18] Ibid

The interim reform options are at the conceptual stage, meaning further work, including a detailed assessment of implementation costs, would be required to establish how they could operate in practice. ENA strongly supports a rigorous evaluation of the costs and benefits of implementing access reforms to ensure they deliver a net benefit to customers before committing to any reform program.