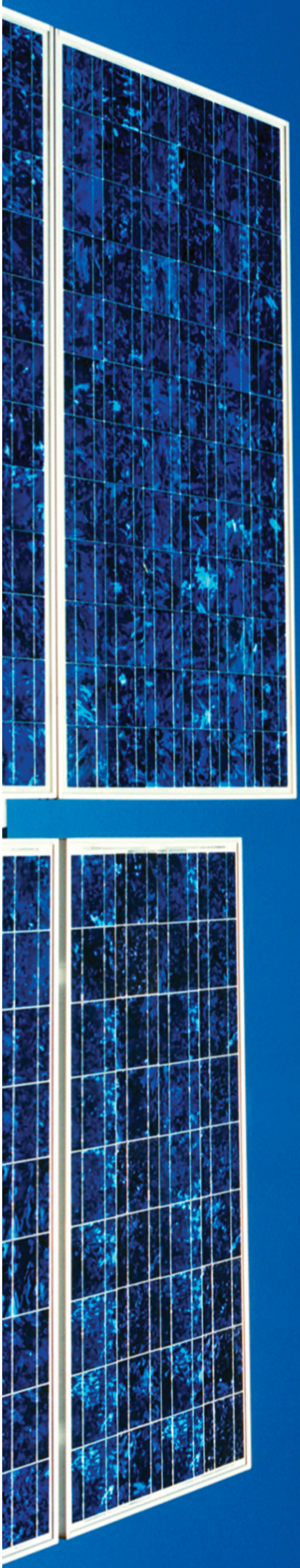

Distribution Market Models

PRELIMINARY ASSESSMENT OF SUPPORTING FRAMEWORKS

Report for the Australian Energy Council

June 2017

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In preparing this report, we have had access to information provided by other consultants engaged by the Australian Energy Council and publicly available information. We have relied upon the truth, accuracy and completeness of any information provided or made available to us in connection with the Services without independently verifying that information. The publicly available information used in this report is current as of 12 May 2017. We do not take any responsibility for updating this information if it becomes out of date.

This report provides a summary of KPMG's findings during the course of the work undertaken for the Australian Energy Council under the terms of the engagement letter.

Any findings or recommendations contained within this report are based upon our reasonable professional judgement based on the information that is available from the sources indicated. Should the project elements, external factors and assumptions change then the findings and recommendations contained in this report may no longer be appropriate. Accordingly, we do not confirm, underwrite or guarantee that the outcomes referred to in this report will be achieved.

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Executive Summary

Distributed Energy Resources (DER) are generally defined as devices which are located at a customer's premises and are able to inject power into the local distribution system, such as embedded generation or battery storage resources, or which assist in the management of load at the premises. DER have the potential to provide value in multiple realms across the electricity supply chain including energy and support services to networks and therefore present substantial opportunities for market efficiency and challenges to the current regulatory frameworks.

KPMG has been asked by the Australian Energy Council (the Council) to evaluate the frameworks required in order to promote efficiency and competition in DER services, with a strong focus on the role of distribution networks. We have based our assessment on the current National Electricity Rules (NER or the Rules) and the Electricity Network Association (ENA)/CSIRO Electricity Network Transformation Roadmap (Roadmap).

The Roadmap has been developed to provide detailed milestones and actions to guide an efficient and timely transformation of the industry over the 2017-27 decade.[1] The Roadmap describes how the role and functions of a distribution business could change, including identifying potential new functions, drawing on international experience to date, In doing so, the Roadmap attempts to provide an integrated set of actions to enable balanced, long term outcomes for customers, enable the maximum value of customer distributed energy resources and position Australia's networks for resilience in uncertain and divergent futures.[2]

The Roadmap sets out a proposal for the network services component of DER. Specifically, it proposes the establishment of a network optimisation market (NOM) to enable distribution network service providers (DNSP) to procure DER for the purposes of Network Support Services (NSS). That market will be supported by a range of advanced networks optimisation (ANO) tools, in recognition of the need to deal with the impacts of distribution generation resources on the network. The Roadmap states that the development of a NOM is a critical development to allow network businesses to unlock the potential for DER services to optimise network operations and reduce network costs in Australia.

This report evaluates the frameworks needed to support the development of competitive markets in DER, across all the potential value streams. While the NOM represents a sub-section of the overall market for DER, we have considered how this could impact on other DER markets, such as trading of other products or services from DERs, including electricity, or the integration of other competitive markets established to facilitate such transactions.

The Roadmap is a substantive piece of work, and its preparation included commissioning analysis from independent consultants, as well as consultation with a wide range of stakeholders. As such, it is a very useful contribution to the debate. Nonetheless, on such transformative issues, a diversity of perspectives is essential, and the Council is keen to assess any potential concerns in relation to the role of the DNSP as proposed by the Roadmap. The Council has also requested KPMG to, where relevant, raise alternative approaches which could better promote the competitive and efficient delivery of services enabled by DER.

[1] Energy Networks Australia and Commonwealth Scientific and Industrial Research Organisation. Electricity Network Transformation Roadmap" Final Report. April 2017
[2] Ibid.

Our Approach

Efficient investment in and operation of DER is best achieved through competitive markets, where the owner of the DER asset is free to offer its services to whichever party places value on that service. The objective of this report is to understand whether there are any potential impediments under the existing frameworks and their potential transformation described under the Roadmap to the efficient investment in and use of DER, and specifically the emergence of competitive markets for DER services.

A focus of the analysis is to understand how, through the exercise of its functions (including those proposed by the Roadmap) a DNSP could impact on the efficiency of DER services and the development of competitive markets, under a future scenario of high penetration of DER in the market.

Our assessment applies the following steps:

1. Identification of the following six elements of the market and regulatory arrangements where the actions and behaviour of a DNSP will influence the efficiency of DER investment and operation;[3]

Procurement of network support services	Co-optimisation between markets	Network tariffs	Distribution system operation	Network access and connection	Network planning and investment

2. For each element, propose a set of principles and market outcomes which we consider need to be satisfied in order to achieve efficiency in DER investment and operation. These provide the assessment principles;[4]
3. Summarise the Roadmap's proposed arrangements relevant for that element;
4. Assess the ability of the current and Roadmap's arrangements to deliver the identified element against the assessment principles; and
5. Set out our findings and advice.

Figure 1 presents an overview of the potential interactions between DER and DNSPs. In presenting these interactions, we have recognised that the current role of the distributor is two-fold:

a) as a distribution network owner (DNO) who is responsible for building, maintaining and owning the network, and

b) as a distribution system operator (DSO) who has responsibility for managing the distribution network operationally and the provision of distribution services.

The DNSP will influence the development of competitive DER markets through both:

- The procurement of DER for NSS from the owners of DER. This includes using DER either for deferring capital projects or as an ancillary service for short-term operational support; and

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[3] In this report, we have defined DER as covering any assets which have the potential to change the energy flows (imports or exports) at the customer meter and includes both passive devices and those devices which can respond automatically to a remote signal. This differs from the definition used by the AEMC which limits the scope of DER to only those devices which can respond automatically to a remote signal which changes the energy flows (imports or exports) at the customer meter.

[4] In defining these principles, we have built on the principles proposed by the Council, the Roadmap Balanced Scorecard, and the principles proposed by the AEMC. Where relevant, we have also incorporated the Grid Neutrality Principles developed to promote a more open grid and to facilitate the increase in DER into our assessment criteria (see Section 3).

- Even where the DNSP does not procure the DER, its policies and decisions across the elements will influence the value that can be realised from that DER in areas unrelated to the provision of NSS.

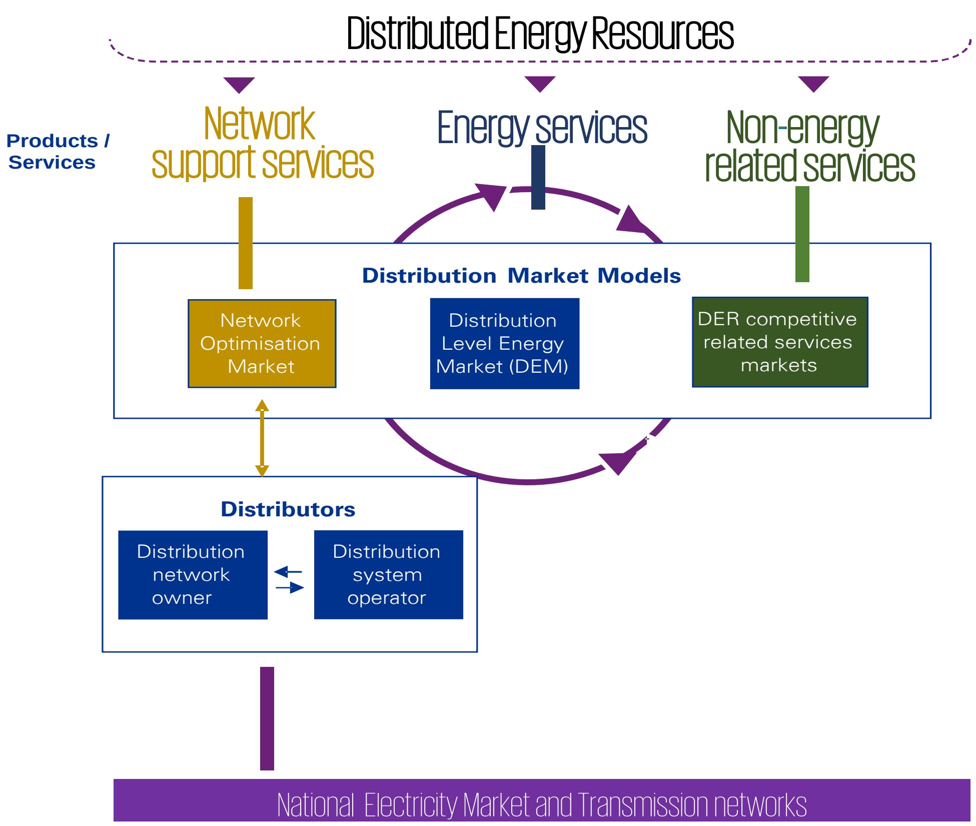
This report primarily assesses how the role of distribution business could influence the development of competitive markets in DER. Given the requirements to operate and maintain their network in accordance with safety, security and reliability standards and their position as the only buyer of network support services, distribution businesses are likely to be material to be efficient development of DER.

Our assessment is based on the six different elements of the market and regulatory arrangements where the role and behaviour of the DNSP could have implications. These influences are likely to become more complicated over time as service offerings mature and new technologies enter the market.

Under the current arrangements, a DNSP may also own DER as a non-network solution in support of operating the regulated network. While we note that direct ownership of DER may create additional issues regarding the interactions between a DNSP and DER, we have not explicitly considered these issues as this matter is currently being considered by the Australian Market Commission (AEMC).

We note that a number of related issues are currently being considered by the AEMC through the Council's contestability rule change, including whether a DNSP can also own a DER as a non-network solution in support of operating the regulated network. Given that, we have not covered these issues in detail but note that the approach decided by the AEMC could impact on our findings.

Figure 1. DER services and DNSP interaction



Findings and Advice

This summary presents the key findings of our assessment. Further explanation and reasoning supporting these findings is contained in the report which we encourage readers to read.

The continued uptake of DER may require the active management of bi-directional electricity flows within a distribution system in a manner that allows co-optimisation across a range of services, including energy supply, and provision of ancillary and network support services. When multiple parties offer DER-related products or services and there is potential for DER to transform the electricity markets and create substantial savings for customers, the role of a DNSP will come under greater scrutiny.

For each of the six elements of market and regulatory arrangements, our assessment identified a number of potential constraints to the efficient development of DER in addition to areas where further work is recommended. Our findings for each element are presented in Table 1 at the end of this summary.

Across all the elements, we have identified the following three key risks which could impede the development of competitive markets in DER.

1. **The ability of DER to be co-optimised across multiple value streams could be constrained**

   The value of DER is maximised when it is able to be co-optimised across multiple value streams. The emergence of competitive market platforms will create more opportunities for DER resources to tap into different revenue streams. The ability of DER to be co-optimised across multiple value streams, including DNSP's procurement of NSS, will depend on:

   - The DNSP providing clarity to the DER owner as to when and how often the NSS service is likely to be required, and the value of that service, so that the DER resource can be efficiently utilised at other times;
   - The terms and conditions under the DNSP's procurement of the DER resource for network support services, including the penalty rates for non-compliance as a result of penalties incurred by the DNSP (for example, under the Service Target Performance Incentive Scheme (STPIS));
   - How the DNSP translates its obligations to maintain a reliable, safe and secure network in access and connection arrangements for DER; and
   - Whether the network optimisation market (NOM) proposed under the Roadmap would allow the concurrent operation of competitive platforms and how it is proposed that these interrelate and allow the efficient resolution of co-optimisation issues.

   The role and behaviour of DNSPs towards DER can potentially create a barrier limiting the ability to "stack" the incremental values a DER may provide to the wholesale market, distribution networks, retailers and customers. This is because a DNSP will approach its interactions with DER on these four issues from their own perspective and obligations. Therefore there is a risk of mis-alignment between the interests of networks and boarder market efficiency with respect to the use and procurement of DER.

2. **The ability of DNSPs to procure DER directly from customers is likely to impede the development of competitive DER markets and limit the ability of DER to capture the full value of its services.**

   This is due to:

   a) The potential for a DNSP to under-pay the DER owner the associated network value. This is a reflection of the DNSP being the single buyer of NSS and is complemented by the cost minimisation incentives under the economic regulatory framework. The current lack of transparency on the potential network value from DER adds to this risk.[5]

b) The potential that a DNSP will place restrictive control terms on DER which prevent it from accessing other sources of revenue. While this is driven by the reliability arrangements governing DNSPs, it is also influenced by the DNSP's risk approach and preferences. There is a risk of inefficient outcomes if such control terms do not maximise market efficiency from DER while achieving the required level of reliability. As the DNSP may not be exposed to the wider market benefits from DER, it may place a greater onus on reliability rather than flexibility.

c) While acknowledging that optimisation of DER value is a complex question, procurement of DER services directly from customers by DNSPs may not result in the optimisation challenge being solved effectively as this places the onus to solve co-optimisation directly onto the customer, who is unlikely to have the ability to resolve it alone.

A DNSP may choose to continue to develop its own products and services to offer to customers (such as the existing load control products). This could create a barrier to other competitive products if the DNSP is inclined to look more favourably on the products it has developed (and less favourably on products developed within the competitive market, such as those developed by retailers or other third parties). A DNSP will always have a greater understanding of what its own products can offer and the associated risks, and will be able to design those products to match its own preferences. There may also be an incentive associated with the ability to include such assets in their regulatory asset base (RAB).

How DNSP's approach the risk of non-delivery of a contracted DER service will determine the conditions placed on the DER service and its ability to access additional revenue streams. Based on current incentives, the DNSP are likely to either pass all the risk on to the customer or seek to resolve the risk through having automatic control over the DER asset (which in turn requires an investment by the DNSP in the control technology).

Alternative approaches where customers participate through an intermediary/aggregator will allow delivery, co-optimisation and performance risks to be managed between the network business and the aggregator, rather than falling to the customer. Such alternatives are likely to result in a better allocation of risks and the promotion of the development of competitive DER services as they allow the use of DER to be adaptive to the particular market circumstances that are occurring.

3. **Potential conflict of interests for the DNSP, especially if the distribution system operation role remains integrated within the distribution network service provider.**

A DNSP's financial interest in DER services does not necessarily depend on whether the DNSP owns the DER asset (either directly or indirectly through related parties). A financial interest could still exist through:

a) The procurement of services from DER owners by the DNSP, depending on the design of those contracts and how the associated costs are treated under the economic regulatory framework.

b) DNSP investment in a market platform (such as the digital NOM) to purchase DER for network support services.[6]

[5] By contrast, the competitive dynamic inherent in the energy market should drive up the value offered to customers.
[6] The Roadmap proposed implementing "network optimisation" systems, such as the Network Optimisation Market ("NOM") platform to better aid the efficient procurement of network support services.

c) A DNSP incurring costs associated with developing its own products to procure DER directly from customers (i.e. investment in automation control technology).

Where the DNSP has a financial interest in DER, this can lead to conflicts regarding how it operates its distribution system. This is unlikely to be a material problem in the short term given current capability in the network. However, there could be a risk in the future depending on the extent to which a DNSP becomes a more active system operator, balancing energy flows at a distribution level. A DNSP may find itself in the future conflicted between the use of its own products (including market platforms), financial payments and system operation.

We also note that this matter of potential conflict of interests could be complicated by two further developments.

Firstly, with the large sunk costs of the distribution networks, DNSP management could increasingly become focused on the associated risks, e.g. around stranded assets. At best, this is a distraction from its DSO role; at worst, it could create conflicts for the DNSP between acting in the consumer's interest and acting in the interests of its DNO role. There will be a need therefore to consider whether the risks of potentially stranded network assets under a high DER scenario should be resolved to remove any perceived conflicts of interests within DNSPs.

Secondly, there could be a considerable first mover advantage for the DNSP to establish a market platform for DER related products or services before any commercial platforms for DER services emerge as this could influence:

a. how the regulator evaluates expenditure proposals for such investment; and

b. how the DNSP recovers the costs associated with their own market platforms.

This could in theory encourage the DNSP to hinder the development of other competitive platforms for other DER transactions.

Even in the absence of a direct financial interest, the development of competitive DER markets could be impeded if there is a perception of bias within the DNSP by stakeholders and investors. The negative impact on market confidence of possible perceptions associated with how the DNSP behaviour influences the development of DER services should not be under-estimated. This issue and the potential separation of the distribution roles between distribution system operator (DSO) and distribution network owner (DNO) has not yet been explored under the Roadmap.

The move towards cost reflective tariffs has the potential to alleviate these three risks. The ability of network tariffs alone to promote efficient consumption and production decisions of customers and hence alleviate network constraints will determine the extent to which the DNSP will need to contract separately and procure DER to support network operations. In addition, cost reflective tariffs provide the certainty and transparency needed for long term investment in DER as it removes any risk that the economic viability of DER is dependent on the DNSP entering into a future contract.

For the reasons discussed in this report, there are challenges to the effective implementation of cost reflective tariffs. This means that other mechanisms for DNSPs to reward and assist DER will continue to play an important role going forward. There is also a risk that DNSPs may, over time, become less encouraged to design tariffs to correctly address network peak demand growth, if they believe they can manage this through direct DER procurement with consumers.

Potential Alternative Approaches

Given the risks identified above, we advise that there is a need to reform the arrangements governing the nature of the DNSP interactions with DER to ensure that the DNSPs exercise their functions consistent with the long-term interests of customers. This report raises the following as potential alternative approaches:[7]

a) Placing increased regulatory monitoring and information disclosures on DNSPs;
b) Placing restrictions on the DNSP regarding how it procures DER for network support, e.g. restriction on direct procurement from customers or a requirement to use competitive markets;
c) Reforming the role of the DNSP, such as structural separation of the DSO and DNO roles and responsibilities; or
d) Changing the economic regulatory framework governing DNSPs, for example reforming the legislated reliability standards.

This report does not make any recommendations on alternative approaches. There is considerable uncertainty regarding the potential development of DER and the materiality of these constraints, and risks will vary over the different stages of market development and the level of DER deployment.

In addition, our analysis of the materiality of these risks depends on expected distributor behaviour in the future under a high DER scenario. However, the anticipated behaviour may not eventuate and, for these reasons, we do not consider it prudent to make firm recommendations in the absence of further analysis and discussion. Rather, we would like to make the following comments.

To date, the economic regulatory framework has attempted to resolve any perception of DNSP bias to its own products (and capital expenditure (capex)) through piecemeal additions to the Rules, mainly in the area of information disclosure. Such an approach is unlikely to be effective under a high DER scenario as it can over-complicate the arrangements, not keep up with changes in technology and may not provide confidence to the market. In addition, greater information disclosure by itself will not be sufficient. There will also be a need to establish clear principles on outcomes consistent with the National Electricity Objective (NEO) and monitor outcomes and DNSP decisions against those principles.

Therefore, a key risk is the pressure placed on the role of regulatory frameworks and the regulator to ensure that the outcomes best promote customer interests. The regulator will be put in the position of making expenditure assessment of DER-related technology and managing potential conflicts of interest between DNSPs' active involvement in DER and system operation.

The difficultly of this increased pressure on the regulator will depend on the resulting uncertainty and complexity associated with DER. The Roadmap predicts that by 2027 over 40% of customers will have some form of DER. This penetration of DER is expected to lead to increased volatility and unpredictability in network flows requiring the DNSP to have better system management tools and the ability to access the potential of DER to manage network costs.

It is not guaranteed that increased penetration of DER and the resulting DER services will lead to increased pressure on network capacity and security. DER could instead make customers more responsive to signals which will remove some of the operational need for active control by distributors. In addition, with the high level of automation to DER technology (e.g. battery management systems), forecasting flows and customer behaviour could become more predictable.

[7] Under the assumption that tariff reform will not adequately resolve the risks.

In any event, any network impacts are unlikely to be uniform - both in time and magnitude - across all distribution networks. This uncertainty is likely to be exacerbated as differing technologies come to market, with varying operating profiles. We consider that such uncertainty will make it difficult for the Australian Energy Regulator (AER) to evaluate each DNSP's expenditure proposal associated with ANO and NOM.

Given the risks and costs of regulation, we advise that there is a need to consider how best to promote the development of competitive providers of DER services and commercial platforms. Competition and non-discriminatory access are, where practicable, the best mechanisms for providing services to customers at an efficient cost.

Fostering the development of competitive third party providers and competitive platforms could be a better alternative than attempting to regulate outcomes under DNSP procurement models. Markets that are co-optimised by design will be more efficient and hence attract more participants.

A DNSP will always have a greater understanding of what its own products can offer and the associated risks, and will be able to design those products to match its own preferences. Nevertheless, DNSPs must be encouraged to utilise the most efficient source of DER, whether it is sourced in-house or from customers or via third parties. Therefore, there will be a need for increased regulation and transparency to align the behaviour of network businesses to the wider market efficiency, as well as to ensure that there is no preference or incentives for the DNSP to favour its own DER products or its own market platform over other providers.

The development of the arrangements for DER should be driven by consumer choice and preferences, and the role of market design and regulatory frameworks is to align individual decisions with the long-term interests of consumers more generally.

Way forward

To progress the issues identified in this report, we recommend that the Council follows two courses of action:

1. Facilitate industry agreement on a detailed list of principles for DER which best promote the interest of customers.
2. Implement a work program to address the potential constraints and risks which will influence the development of DER services not covered under the existing frameworks.

Principles for future market and regulatory design

This report assesses the ability of the existing frameworks (and where appropriate the Roadmap's proposed amendments to those frameworks) to promote the efficient use of DER and the development of competitive markets against a set of detailed principles. These principles are an attempt to provide more guidance on the desired outcomes and market characteristics consistent with maximising the efficiency of DER to the market. In developing these principles, we have built on the framework used by AEMC and ENA/CSIRO and have included the principles of grid neutrality published in the United States.

These principles have been developed in the context of promoting the NEO. We believe there is merit in facilitating industry agreement on a set of principles needed for market and regulatory design under the future scenario of high DER deployment. Such principles can be used as a blueprint to consider policy options and would provide greater confidence to the market and investors. The principles proposed in this report could be used as a starting point for this process.

Future work

Our assessment has shown there to be a number of policy gaps under the existing frameworks requiring further consideration in the development of markets for DER related products and services.

In certain cases these gaps have been similarly identified, with potential solutions proposed, under the Roadmap.

These solutions have been designed to deliver significant benefits to customers, providing an opportunity for customers to maximise the return on their investment while also helping reduce network expenditure. For example, the Roadmap promotes streamlining of connection arrangements for customer technologies providing for a nationally consistent process, supporting new market entrants and innovative services. Further, the Roadmap supports network services providers expanding its information services in order to enhance their interactions with customers. Through improved data analytics and digitalisation of services, customers are to be provided with improved access to data, information and connection services.

Given the extent and diverse nature of these areas for further work, we have also considered the timing and appropriate sequencing of conducting the analysis for each issue. As a first step to aid discussions, we have organised the 14 issues into these time-periods (see Figure 2):[8]

1. Within the next 12 months;
2. Within the next 1-3 years; and
3. After the next three years.

[8] How these 14 future areas for work relate to each of the six elements is presented in Table 7 (section 11.3.2). Some tasks will address more than one element.

Figure 2. Proposed Sequencing of Future Work to address identified policy gaps

Within next 12 months

- Issue 1: Clear and effective operational procedures and boundaries in relation to how a DNSP may use DER
- Issue 2: Development of the regulatory and market arrangements to facilitate peer-to-peer transactions
- Issue 3: Development of new connection standards for DER
- Issue 4: Transparent framework for managing DER connection requests in areas where there is limited hosting capacity
- Issue 5: Definition and ability for DER to be used as a firm alternative to network asset

Within next 1-3 years

- Issue 6: Provide effective and clear information to consumers regarding their DER capability and how to maximise value from their investment
- Issue 7: An options study on how to address the potential risk of stranded assets under a high DER scenario
- Issue 8: A review of pricing principles for residual network charges
- Issue 9: Transparent and credible methodology on how the DNSP calculates prices for DER services
- Issue 10: Technical assessment of the ability of distribution networks to manage to increase DER penetration

3 years +

- Issue 11: Review separation of distribution system operation role and the network owner
- Issue 12: Review of current Rules that could prevent different network tariffs being considered
- Issue 13: Consider the role of reliability standards under a high DER scenario and in particular where some form of "export reliability standard" is required
- Issue 14: Framework for collecting and sharing data across market participants

Summary assessment against the proposed principles

Market and regulatory element	Principles to promote efficiency and competition in DER	Applicable Roadmap proposals	Assessment **against current rules and relevant roadmap proposals**	Advice
Procurement of network support services	• DNSPs have the ability to utilise DER for network support, especially as network tariffs may not deliver the required customer response; • Payment for NSS is compensative of the risk adjusted value derived by the DNSP; • There is a transparent and credible methodology on how the DNSP calculates the prices for DER services; • Clear and effective operational procedures and boundaries have been established in relation to how a DNSP may use DER; • A DNSP is prevented from taking advantage of its position as single buyer of NSS; and • Risk of non-compliance of DER allocated to the party who is best able to manage that risk.	• Network Optimisation Market (NOM) for the procurement of distributed energy resources services (i.e. network support services) either directly with customers and/or through market actors. • NOM should be integrated with Advanced Network Optimisation (ANO) planning tools. • DNSPs have the ability to procure directly from consumers. • As processes and technologies mature, this market is expected to move to a more sophisticated digital platform (dNOM).	• Direct procurement by DNSPs from customers creates risks and issues for both the owner of DER and also to market efficiency. The materiality of these risks will vary over the different stages of market development and the level of DER deployment: o There is potential for a DNSP to under-pay the DER owner the associated network value - reflective of the DNSP being the single buyer of network support services and is complemented by the cost minimisation incentives under the existing economic regulatory framework. o The current lack of transparency on the potential network value from DER adds to this risk. By contrast, the competitive dynamic inherent in the energy market should drive up the value offered to customers. o The prospect of a DNSP directly procuring network support from the DER creates issues of enforcement and compliance, and this may require a means to financially penalise the DER if it fails to comply. For example, a DNSP could potentially pass through any loss of revenue under the Service Target Performance Incentive Scheme (STPIS) for the DER's non-compliance. In addition, the DNSP having the direct means to control the technology may prevent the DER owner from accessing other	• As a monopsony buyer of NSS, consideration must be given to the risks resulting from a DNSP's potentially advantageous position including ensuring DER owners / third parties are insufficiently informed or prepared to enter into such negotiations or contractual arrangements. • A DNSP should be encouraged to utilise the most efficient source of DER, regardless of whether that DER is sourced directly from customers or via a third party retailer or aggregator. • Under a high DER scenario, there will be a greater need for regulation of DNSP procurement of DER (addressing potential bias or discrimination and ensuring market confidence). o Such regulation will add to the burden on the regulator to design the arrangements correctly to best promote market efficiency. • DNSPs should continue to have the ability to procure directly from customers, especially in the short term. Not doing so would prevent consumers from accessing potential sources of value associated with their investment and reduce support for the development of DER technologies over the long term.

Market and regulatory element	Principles to promote efficiency and competition in DER	Applicable Roadmap proposals	Assessment **against current rules and relevant roadmap proposals**	Advice
			revenue from competitive DER-related products. Retailers or other intermediaries might create more flexible risk management options in this context, resulting in greater utilisation of DER. o Some consumers may not have the means and ability to fully understand and evaluate any offer from a DNSP for network support. There is a risk that consumers do not make an informed choice. While this may be an issue to all forms of DER procurement, there may be additional confusion from a DNSP attempting to procure directly from customers given existing relationships. o To procure directly from customers will require the DNSP to develop its own products and solutions in order to offer them to customers (such as the existing load control products). This could create a further barrier to other competitive products if the DNSP is inclined to look more favourably on the products it has developed and with which it is familiar and potentially have a financial incentive (and less favourably on products developed within the competitive market, such as those developed by retailers or other third parties). o It is not clear if DNSP procurement will provide long-term certainty for DER owners over the investment life under the current economic regulatory framework given the five year regulatory control period. However, this may not be an issue given that a considerable amount of DER investment may be driven by personal circumstances (e.g. better management of electricity bills).	Future areas of work include: • Developing a transparent and credible methodology on how the DNSP calculates the prices for DER services • Establishing clear and effective operational procedures and boundaries in relation to how a DNSP may use DER • Consideration of how to provide effective and clear information to consumers regarding their DER capability and how to maximise value from their investment • DNSPs should be encouraged to utilise the most efficient source of DER, whether it is sourced in-house or from customers.

Market and regulatory element	Principles to promote efficiency and competition in DER	Applicable Roadmap proposals	Assessment **against current rules and relevant roadmap proposals**	Advice
Co-optimisation between multiple markets	• The ultimate decision on how DER is utilised across buyers is with the owner of DER; • Any potential conflict between market operators[9] (MO) and the DSO are transparently managed (e.g. through information exchange); • Clear separation of responsibilities between MOs and DSO; and • Orchestration of DER services across multiple markets is achieved in a manner consistent with efficient outcomes.	• In relation to the co-optimisation of the system, the ENA/CSIRO Roadmap provides for an initial approach to be established by 2019, coordinating and optimising the decisions of the independent market operator and distribution connection points in real time and using automated signals. • While the ENA/CSIRO Roadmap does not explicitly discuss the optimisation of multiple DER related markets, it is proposed that a multi-application platform be developed enabling the application of a common set of network, security and integration services. The ENA/CSIRO consider this approach will provide independence without restricting resources to any one particular hardware platform.	• Under a high DER scenario, there could be a need to coordinate the deployment of DER across multiple markets. In delivering NSS, a DER will generate, or consume, energy at times that are of most value to the distribution network. In delivering energy, on the other hand, the DER will operate based on the value to the wholesale energy market and other market participants. Whilst these times might coincide, often they will not. Therefore, co-optimisation will be important for promoting the efficiency of DER through allowing customers to capture the full value of their DER asset. • For a DNSP to establish a market for procurement of network support services creates questions as to how this market should interact with other commercial platforms for DER services, as well as whether the establishment of such a market will impact on the commercial viability of such platforms. • Markets that co-optimise by design should be more efficient and hence attract participants. Therefore, regulation may be unnecessary, although this depends upon other factors such as free-riding, transaction costs, and coordination costs. If a commercial platform is effective at marketing and co-optimising the multiple DER-provided services, this should lower the price of NSS and encourage the DNSP to use it.	• Markets that co-optimise by design should be more efficient and hence attract participants. • The nature and design of commercial platforms will vary and likely go through multiple stages of design with increasing levels of sophistication and scope as experience is gained and the approach is proven. It is vital that each market provides for open and transparent participation in order to facilitate co-optimisation of market outcomes. • Effective and real time communications between network and market operators of individual platforms may be required as platforms become more sophisticated. • Payment (and cost recovery) for such infrastructure across regulated NOM and commercial markets will require further consideration – these remain uncertain under the current NER. • It is important for the framework going forward that it does not create any preference or incentives for the DNSP to favour its own market platform over other platforms. • There is a potential risk that co-optimisation will not be properly considered at the start of a market, particularly where multiple markets are established targeting specific technologies, participants or even individual networks, and therefore will become an issue

[9] By market operators, we mean any party responsible for managing and clearing transactions related to energy and/or DER services. This covers AEMO as the market operator for the wholesale market, the DNSP nominated entity for the NOM in addition to any market operator for a commercial DER platform. As there could be multiple platforms there could be numerous market operators in the future.

Market and regulatory element	Principles to promote efficiency and competition in DER	Applicable Roadmap proposals	Assessment **against current rules and relevant roadmap proposals**	Advice
			• However for a DNSP to use commercial platforms for the procurement of NSS, a degree of trust will be required in the ability of such platforms to deliver, especially in the early stages of development. DNSPs are likely to have an understandable preference for their own products and solutions. In addition, there could be a considerable first mover advantage to establish market for DER related products or services before any commercial platforms emerge. • It is important for the framework going forward not to create any preference or incentives for the DNSP to favour its own market platform over other platforms. There is a need to ensure that the NOM is open and transparent, to facilitate co-optimisation between NSS and energy service delivery. Also DNSP policies and operations will need to be assessed and monitored to ensure they do not favour one market over another. • The co-optimisation of markets needs to be fully considered at the design stage and evaluated under any regulatory approval of investment. Trying to retro-fit the appropriate arrangements may be too difficult and creates uncertainty for the market.	for attempting to retro-fit solutions for co-optimisation. Future areas of work include: • Development of the regulatory and market arrangements to facilitate peer-to-peer transactions • Establishing a framework for collecting and sharing data across market participants • Establishing clear and effective operational procedures and boundaries in relation to how a DNSP may use DER.
Network tariffs	• Provide compensation for network value delivered by DER; • Promote efficient investment in DER; • Allocate costs based on use and causality;	• Accelerated transition of customers towards more cost reflective tariffs and implementation of new pricing options (recognising the difference between those with DER and those without)	• The design of network tariffs which will best promote the development of DER – locational, coincident demand charges – are unlikely to be implemented given current political concerns. However, this does not mean that tariff reform will not be important for DER development, and tariff reform still needs to be conducted in the way which delivers most efficient outcomes. Regarding tariff reform, we found:	• Tariff reform is difficult and contentious and relies heavily on getting a social licence from community and governments in order to be effective – there is a need to recognise that alternative mechanisms will be needed to transfer network value to the DER owners. • There are limitations with the current pricing principles that will impede the development of DER with little consideration to date on the

Market and regulatory element	Principles to promote efficiency and competition in DER	Applicable Roadmap proposals	Assessment **against current rules and relevant roadmap proposals**	Advice
	• Customers are provided with tariffs which they understand and are able to respond to; and • Alignment of risks and rewards.	• Amendment of network tariffs with residential and small business customers assigned to new (opt-out) demand based tariffs by 2021. • From 2021, new tariffs to be introduced differentiating between services whereby certain customers may be self-sufficient at certain times and/or others who may wish to trade on a non-traditional platform. • By 2027, amendments to tariffs lead towards the dynamic and locational based use of DER and specifically the selling of services by customers directly to networks or through their agents.	o DNSP proposed demand tariffs are not totally reflective of network value as they are based on non-coincident peak and are not locational specific. Since it is coincident demand that drives network augmentation costs, such tariffs are only cost-reflective to the extent that the coincident and non-coincident maximum demands happen to occur at the same time. For residential customers, this is the exception rather than the rule. o Customers with low usage will - at some point - find it worthwhile disconnecting from the grid and, increasingly, the grid will be de-populated as the residual charge increases. The Roadmap recognises this risk from fixed charges, and proposes a discounted tariff for those liable to disconnect from the grid. This is an important start, but further analysis is required as to how best to structure residual charges to all customers. o Constraints with current Rules could prevent different network tariff designs from being considered (for example, prohibition on export tariffs under NER clause 6.1.4). o To date, there has been a lack of consideration regarding the appropriate tariff structures for DER transactions. For example, there is a need to consider the cost reflective tariff for peer-to-peer transactions and whether such transactions should be relieved of the requirement to contribute to transmission network costs. o The prospect of asset stranding could discourage DNSPs from tariff reform. The materiality of this issue may increase under an environment of high DER penetration.	appropriate tariff structures for DER transactions (e.g. peer to peer). • The five year lag between tariff structure statements creates a material risk that tariff reforms fail to keep pace with market developments – in particular the ability to provide long term price signals to the market. • It is important to recognise the inter-relationship between network tariff reform and a DNSPs procurement of DER given their incentive to beat the AER's forecasts. Future areas of work include: • Development of the regulatory and market arrangements to facilitate peer-to-peer transactions. • A review of the current Rules that could prevent different network tariffs being considered. • Assessment of the potential risk of stranded assets under a high DER scenario. • A review of pricing principles for residual network charges to remove the negative distribution effects on those consumers who cannot afford to own DER resources and to reduce the incentive to go off-grid.

Market and regulatory element	Principles to promote efficiency and competition in DER	Applicable Roadmap proposals	Assessment **against current rules and relevant roadmap proposals**	Advice
			o The five year lag between tariff structure statements creates a material risk that tariff reforms fail to keep pace with market developments. ● The challenges with achieving tariff reform means other mechanisms for DNSPs to reward and assist DER will continue to play an important role going forward. These mechanisms are discussed in other sections. However, there is a risk that DNSPs may, over time, become less encouraged to design tariffs to correctly address network peak demand growth, if they believe they can manage this through NSS procured with consumers or through capital investment.	
Distribution System Operation	● Responsibilities for the safety and reliability of the local distribution system are clearly specified, transparent and allocated to the most appropriate party; ● The objective of the DSO is to meet the needs of network users at the lowest, long-run cost. The current regulatory framework has been designed in order to achieve this; and ● Conflicts of interest between the DSO role and related business roles, including its role as DNO, should be avoided or managed accordingly.	● The roles of DSO and DNO will continue to be undertaken by DNSPs in an integrated way. ● The operational role of the DSO will become more complex as there will be a need to call upon NSS providers as needed to manage network constraints. ● DNSPs will be required to adopt new protection systems and forecasting and planning approaches, including the ability to anticipate distribution system constraints – a component of an integrated control and monitoring architecture.	● A DNSP's financial interest in DER services does not necessarily depend on whether the DNSP owns the DER asset (either directly or indirectly through related parties). A financial interest could still exist through: o the procurement of services from DER owners by the DNSP depending on the design of those contracts and how the associated costs are treated under the economic regulatory framework o DNSP investment in a market platform (such as the dNOM) to purchase DER for network support services o a DNSP incurring costs associated with developing its own products to procure DER directly from customers (i.e. investment in automation control technology). ● Where the DNSP has a financial interest in the usage of DER, this can in theory lead to conflicts regarding how it operates its distribution system. This is unlikely to be a material problem in the short term given current capability in the	● Perception of independence will be key for market confidence. ● In considering the possible separation of a DNSP into its two roles as DNO and DSO, there is a need to consider the following: o the exact point of delineation between the two roles o the form of separation of DNO and DSO (discussed further below) o how to regulate the two differing roles including identification of the potential financial implications in setting revenues and prices for each o how to deal with existing network assets. ● Treatment of any existing DER assets owned and operated by a DNSP must be considered to ensure the market's competitiveness and efficiency. ● Conflicts and risks associated with DNSP ownership of DER are likely to grow over time and future separation of DER ownership from

Market and regulatory element	Principles to promote efficiency and competition in DER	Applicable Roadmap proposals	Assessment **against current rules and relevant roadmap proposals**	Advice
		• To support planning and operation in the face of DER penetration, DNSPs will develop and use ANO tools. • DNSPs will use the ANO tools to identify emerging distribution constraints and to identify and compare network and non-network solutions DNSPs will use.	network. However, there could be a risk in the future, depending on the extent to which DER and smart technologies enable distributors to become more active in system operations needing to balance energy flows at a distribution level. In this future scenario, a DNSP may find itself conflicted between the use of its own DER and that of another consumer or market actor. • There will be advantages and disadvantages to separating the DSO role from the DNO role within the DNSP. Consideration on this issue would provide certainty for the market, including identifying the potential future circumstances where separation between the distribution system operation and network ownership would be better for customer outcomes. • Specifically, where a DNSP has a positive financial interest, it will naturally favour its own DER over the use of others connected within the location. Even if there is no financial interest, any perception of a conflict or lack of independence will dampen market confidence and investment in DER.	a DSO may become more difficult and complex. • Where benefits and costs of DNSP separation are dependent on the level of DER penetration, one could estimate a "breakeven" level of DER penetration at which separation becomes desirable. • In any case, a transition pathway facilitating any proposed structural changes to the role of a DNSP must be developed. • Consideration of the potential for stranded assets and possible changes to the regulatory treatment of such assets could in theory, also influence how DNSPs view the development of the DER. Future areas of work include: • technical assessment of networks' current ability to manage an increase in DER penetration and whether to develop threshold tests • identification of the circumstances where separation of the distribution system operation role and the network owner would be necessary • establishing clear and effective operational procedures and boundaries in relation to how a DNSP may use DER • establishing a framework for collecting and sharing data across market participants.
Access and connection	• Access to the network is on an open and non-discriminatory basis; • Connection and access standards need to be fair,	• A stated driver of the ENA/CSIRO Roadmap are "customers' expectations of a responsive grid, enabling streamlined	• DER technologies, such as solar PV and batteries, have different technical characteristics to load and different impacts on the safety and quality of distribution. Therefore, rights and obligations around connecting these	• In any regulatory framework for connection and access, the safety and security of the network must remain paramount. However, this should not be unfairly used by a DNSP to

Market and regulatory element	Principles to promote efficiency and competition in DER	Applicable Roadmap proposals	Assessment **against current rules and relevant roadmap proposals**	Advice
	transparent and promote efficient deployment and use of DER[10]; • Network access and connection policies do not unduly constrain the ability of DER to deliver a full range of services; and • Access and connection requirements support market operations of commercial platforms.	connections and a 'plug and play' environment supporting their choice of technologies." • By 2024, network service providers are to take a more active role in facilitating the introduction of new products and services and streamlining of connection to the grid • By 2027, enhanced data analytics and increased use of digital channels enabling improved sharing of information between a network service provider and customer are to contribute to the streamlined connection of products and services by the consumers, aggregators and retailers alike.	technologies behind the meter may likely need to differ from conventional load connections (e.g. a new air-conditioner). However, these rights and obligations are yet to be fully developed, creating uncertainty for DNSPs and consumers. • Any new connection standards should be developed and applied as soon as possible, as opposed to simply waiting for potential problems with existing arrangements to emerge. These should set out simple, fair and transparent connection rights. Obligations and standards are therefore required in order to ensure all DER are able to connect to a distributor's network with minimum transaction costs. Similarly, where a DER connection is either restricted or rationed, for example due to limited hosting capacity, such policies must be transparent and accessible to all potential investors in DER. • Where connection of new generating equipment must be limited, there needs to be some transparency around how, when and where that might occur. For example, the publication of "hosting capacity" information indicates where constraints are approaching. • Reliability standards apply to conventional distribution service, supplying consumer load. There are no corresponding export reliability standards for the new "export" distribution service of accepting consumer exports onto the grid for delivery to HV or the transmission network. Thus, an exporting-consumer's "access" to the network is uncertain. We recommend that consideration be given to whether some form of	prevent a DER from connecting and accessing its network. • Simple, fair and transparent connection rights, obligations and standards are therefore required in order to ensure all DER are able to connect to a distributor's network with minimum transaction costs. • Policies outlining restricted or rationed access/connection must be transparent and accessible to all potential investors in DER. • New connection standards should be developed and applied as soon as possible – as opposed to waiting for problems to emerge. o Failing to do so may create an unfair bias towards early connectors. • Policies and processes may be required establishing "reliability" standards for export service and for associated "export shedding" mechanisms. • Leaving it to the DNSP's discretion under the current arrangements to strike the right balance between market efficiency and safety/security of a network in the connection agreements may not promote the right outcomes. Future areas of work include: • development of new connection standards for DER

[10] Grid Neutrality Principle 5 – Foster open access to the Grid.

Market and regulatory element	Principles to promote efficiency and competition in DER	Applicable Roadmap proposals	Assessment **against current rules and relevant roadmap proposals**	Advice
			"export reliability standard" is required under a high DER scenario. • Providing a DNSP with discretion to strike the right balance between market efficiency and safety/security of a network in the connection agreements may not promote the right outcomes for the market more broadly. This is because there may not be any incentive for the DNSP to take into account market implications and benefits from DER. As a result, any new connection arrangements for DER must reflect market-wide considerations to best promote the NEO.	• development of a transparent framework for managing DER connection requests in areas where there is limited hosting capacity • consideration of the role of reliability standards under a high DER scenario and, in particular, where some form of "export reliability standard" is required • assessment of networks' current ability to manage an increase in DER penetration and whether to develop threshold tests • establishing clear and effective operational procedures and boundaries in relation to how a DNSP may use DER.
Distribution Planning and Investment	• Networks need to provide universal supply at a reasonable cost in accordance with their regulatory obligations;[11] • DNSPs will select the most efficient solution, irrespective of whether it is a network or non-network solution; • The role of the distribution network is to meet the needs of customers (customer centric) through facilitating physical electricity flows that support customer transactions; and	• Significant changes are required to the current design and operational practices for the whole electricity network because of changes to both the type and location of new generation sources. • Development of a range of advanced network planning, operation and intelligence tools and systems over the period 2017 to 2027. o By 2019, the adoption of advanced network planning models, techniques	• The behaviours and actions of the DNSP in planning and investing in the network will have implications for the efficiency of all DER services, not only those procured by the DNSP for NSS. We identified a number of potential constraints and risks which have not been addressed in the Roadmap, including: o The potential for bias towards capital expenditure in favour of operational expenditure. o The over-reliance of current regulatory mechanisms, such as the RIT-D, to support efficient network investment decisions relating to DER. o There is no current regulatory mechanism or transparent methodology which explicitly requires the calculation of the network value from DER in all situations.	• Further consideration is warranted of how to define DER as a firm alternative to network assets. This may assist in mitigating any risk that a DNSP could over specify the terms and conditions needed to achieve "firmness" • Further consideration is required on how future expenditure proposals are to be assessed in light of the need for ANO tools. In order to assist the AER in reviewing future "smart grid expenditure proposals" for ANO tools, the AEMC, AEMO, and the ENA may wish to consider developing a threshold test for high penetration of DER for different network topologies in each jurisdiction in terms of its effects on distribution network security and power quality. • Further work is needed to test whether the current regulatory framework (accounting for

[11] This principle is copied from the Grid Neutrality Principle 1 – Empowering the customer while maintaining access at reasonable cost (see section 3.3.4).

Market and regulatory element	Principles to promote efficiency and competition in DER	Applicable Roadmap proposals	Assessment **against current rules and relevant roadmap proposals**	Advice
	• Networks must not impede competitive markets and therefore need to provide adequate hosting capacity where efficient.	and valuation methods are to have been established, whereby DERs are seen as credible non-network alternatives by distributors. • Intelligence and control architectures and tools at the distribution level to play a foundational role in maintaining safe, reliable and efficient operation of the system under higher DER scenario.	o The current regulatory determination arrangements can make it difficult for DNSPs to manage the expenditure volatility of DER procured (if the price depends on when the DER asset is used for NSS). o A five year regulatory control period cycle may not be provide the right flexibility to support the development of DER markets. Within a five year period, there may be dramatic changes in DER technologies presenting new opportunities and the need for new protection schemes which were not forecasted at the start of the regulatory period. • While a DNSP may need advanced network planning tools and systems to adequately manage operations under the high DER scenario, regulatory funding of such tools or systems may be uncertain under the current model. It is also not clear if a high DER scenario will make flows more variable and unpredictable which will make it difficult for the AER to evaluate such expenditure proposals. The AER would also need to assess whether investment by other parties would provide the required information for system operation. • The framework governing DNSP planning and investment decisions, including the revenue regulation arrangements will have a key role in supporting the development of competitive DER services. This framework has been subject to piecemeal amendments in recent years and is currently subject to a number of rule changes. Such a piecemeal approach is unlikely to be effective as it can over-complicate the arrangements and will not provide confidence to the market.	current rule changes) could act as a barrier in a high DER scenario. Future areas of work include: • development of a definition and ability for DER to be used as a firm alternative to network assets • consideration of the role of reliability standards under a high DER scenario and, in particular, where some form of "export reliability standard" is required • assessment of networks' current ability to manage an increase in DER penetration and whether to develop threshold tests.

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Glossary

AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ANO	advanced networks' optimisation
ANO	Advanced Network Optimisation
APR	annual planning reports
BNL	Berkeley National Laboratory
C&I	commercial and industrial
COAG	Council of Australian Governments
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DEM	distributed energy market
DER	distributed energy resources
DMM	Distribution Market Model
DNO	distribution network owner
dNOM	digital Network Optimisation Market
DNSP	Distribution network service provider
DSO	distribution system operator
DUOS	distribution use of system
ENA	Energy Networks Australia
FCAS	frequency control ancillary services
FIT	feed-in-tariff
FRMP	Financially Responsible Market Participant
IMO	Independent Market Operator

LRMC	Long Run Marginal Cost
MO	market operators
MSGA	Market Small Generation Aggregator
MUA	multiple-use applications
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electricity Rules
NOM	network optimisation market
NOM	Network Optimisation Market
NPV	Net Present Value
NSS	Network Support Services
RAB	regulatory asset base
RIT-D	regulatory investment test for distribution
STPIS	Service Target Performance Incentive Scheme
TNSPs	transmission network service providers
TSS	Tariff Structure Statement
VCR	Value of Customer Reliability
WACC	weighted average cost of capital

1 Introduction

Towards the end of 2016, various market participants, regulators and industry associations in Australia and around the world were contemplating the implications to organised electricity markets of continued penetration of distributed energy resources (DER). This prompted the release of several papers exploring possible responses, and in one instance, significant reform of a sector.[12] These proposals ranged from changes to governing frameworks (such as the National Electricity Law (NEL) and National Electricity Rules (NER)), to proposals for broader functional and operational changes and the concept of a decentralised market for the provision of DER-related products and services.

In Australia, two such reports include the Australian Energy Market Commission (AEMC) consultation paper titled "*Distribution Market Model*" (DMM), and the collective work by the Energy Networks Australia (ENA) and the Commonwealth Scientific and Industrial Research Organisation (CSIRO) titled "*Electricity Network Transformation Roadmap: Final Report*" (the Roadmap).

The AEMC consultation aims to explore how the evolution to a decentralised market for the provision of electricity at a distribution-level may occur.[13,14] In drafting the consultation paper, the AEMC sought to address a wide range of issues, including[15]:

- the technical opportunities and challenges presented by DER;
- what, if any, new roles, price signals and market platforms are required to optimise the development, deployment and use of DER;
- how the role of distributors may need to adapt to facilitate a transition to a more decentralised market for electricity services;
- whether the existing electricity regulatory framework impedes or encourages innovation and adaptation by distributors to support the efficient uptake and use of DER; and
- whether changes to the existing distribution regulatory arrangements, or the design of a new market, are necessary to address any impediments to business model evolution.

The Roadmap sets out a proposal for the network services component of DER. Specifically, the Roadmap proposes the establishment of a network optimisation market (NOM) to enable distribution network service providers (DNSP) to procure DER for the purposes of Network Support Services (NSS). That market will be supported by a range of advanced networks' optimisation (ANO) tools, in recognition of the need to deal with the impacts of distribution generation resources on the network.

While the NOM represents a sub-section of the overall market for DER, it may have implications for competitiveness and efficiency of other distribution-level markets, including the trading of other products or services from DERs such as electricity, or the integration of other competitive markets established to facilitate such transactions.

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[12] New York State Public Services Commission. Reforming the Energy Vision. Website. Last accessed 26 February 2017. Available at: <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument>
[13] Australian Energy Market Commission. Distribution Market Model. 1 December 2016.
[14] The work of the AEMC remains ongoing as of May 2017 with submissions received in response to the consultation from a wide range of market participants including generators, retailers, system and network operators and industry associations.
[15] Australian Energy Market Commission. Website: Distribution Market Model. Last accessed 20 February 2017. <http://www.aemc.gov.au/Major-Pages/Distribution-market-model>

1.1 What were we asked to do?

The Roadmap is a substantive piece of work, and its preparation included commissioning and analysis from independent consultants and consultation with a wide range of stakeholders. As such, it is a very useful contribution to the debate. Nonetheless, the Australian Energy Council (the Council) considers that a greater diversity of perspectives is required and has raised a number of concerns in relation to the breadth of the ongoing role a distributor may have under a market for the provision of DER-related products and services, specifically:

- Does a DNSP need to be fully integrated in the operation and control of a DER market?
- If so, under what circumstances do a DER market and DNSP need to be integrated?
- If a case is made for integration, what are the potential impacts to competition and efficiency for DER and DER-enabled products and services? What regulatory arrangements would be needed to support competition and efficiency?

The Council has engaged KPMG to evaluate the appropriate frameworks required in order to promote efficiency and competition in DER services, with a strong focus on the role of distribution networks. We have based our assessment on the current National Electricity Rules (NER or the Rules) and the Roadmap.

To frame our assessment, the Council has requested specific responses be provided to the following questions:

- The ENA argues that an integrated suite of network planning models for the operation of DER will ensure the technical stability, system security and economic efficiency of the network. What are the potential risks to the promotion of a long-term, competitive market in DER and DER-enabled products and services under the ENA's proposed model?
- Is there an alternative platform or model that would promote a more optimal outcome that addresses carbon constraint, affordability, system security, grid neutrality and customer choice (i.e. coordination through a centralised agency or some other mechanism)? If so, how would this operate in practice including the roles and functions of the different market participants?
- If the ENA model is considered the most effective, what adjustments, if any, would be required to support a long-term, competitive market in DER and DER-enabled products and services?
- Under the optimal scenario, what network access rules should apply to support the effective introduction of additional DER-enabled products and services such as peer-to-peer trading?[16]
- Under the optimal scenario, what pricing principles should apply to DER that are dispatched into the network? In addition, how should any network benefits or cost savings be allocated between the network and the DER provider?

This report details KPMG's assessment and identifies the potential issues and gaps for further consideration for achieving an appropriate market structure for DER products and services.

[16] Peer to Peer trading effectively means the ability for consumers to transact with other consumers for the supply of electricity. Hence, individual customers interact to buy or sell goods and services directly with each other, without intermediation by a third-party, or without the use of a company or business. The buyer and the seller transact directly with each other.

1.2 Our approach

It is clear that the continued penetration of DER will provide multiple value steams to different users including energy and NSS where DER operation is designed to change active power energy flows, or voltage levels, such that constraints on distribution networks are relieved or avoided. This transformation will create opportunities and challenges for existing participants across the electricity supply chain, while also creating opportunities to meet the objectives of policy makers, including governments.

While these opportunities may ultimately benefit a DNSP, they equally may confer an unfair advantage towards a DNSP, creating a risk to other market participants and to the overall competitiveness and efficiency of an individual market. For example, where consumers or market participants are required to consign control of a DER to a DNSP, with limited ability to choose what services are provided and when.

The current regulatory arrangements will influence how the market progresses along a pathway of transformation, facilitating greater penetration of DER and the development of potential markets for their products and services. It is therefore critical to understand the potential impediments and risks to the efficient use of DER resources and the promotion of long-term, competitive markets in DER products and services under the existing and proposed regulatory and market arrangements.

Our approach to understanding these impediments and risks has been to apply the following steps:

1. Clarify the definitions of DER and DER products and services (Section 2);
2. Identify the elements of the market and regulatory arrangements where the actions and behaviour of the DNSP could impact on the efficiency of DER investment and operation (Section 3);
3. For each element, propose a set of key principles and market outcomes which need to be satisfied in order to achieve efficiency in DER services. These provide the assessment criteria given in Section 3;
4. Summarise the proposed arrangements under the Roadmap for that element (Sections 4 to 10);
5. Assess the ability of the current and proposed arrangements to deliver the identified key characteristics (Sections 4 to 10); and
6. Set out our findings and advice on potential regulatory responses and market design principles for consideration in further discussions regarding the development of a competitive DER market (Section 11).

We note the approach proposed by the Roadmap does not yet contemplate the trading of other products or services from DER, including electricity, or the integration of other markets facilitating such transactions. We understand the ENA/CISRO are working on further developing this framework. In assessing the ability of the current and proposed arrangements to deliver the identified key characteristics, we have taken a forward looking view which assumes a high level of DER penetration.

Our assessment has been informed by both domestic and international views on the opportunities and challenges associated with continued uptake of DER, including (among others) work completed in the United States (New York and California) and the United Kingdom.

The issues relating to DER services and markets are relatively new, and there could be a risk of mis-interpretation or confusion on the precise meaning of the terms used in this report. To aid the reader, Section 2 sets out our definitions for the key terms used describing DER, its uses and markets.

1.3 Relevant rule change proposals

The current rule change requests made by the Council and the Council of Australian Governments (COAG) to the AEMC to promote and/or help facilitate competitive markets for new technologies may resolve some of these issues. Each rule change request considers the role of a DNSP, classification of distribution services under the NER and importantly seeks clarity regarding whether a distributor (or transmission operator) may directly supply or own DER.

The AEC has requested that we approach our assessment from a future point in time 10 years from today under a high DER scenario and not to unduly focus on the current issues being explored in the current rule changes being considered by the AEMC.

A summary of the rule changes is provided below.

1.3.1 COAG Rule Change Request: Contestability of Energy Services

The COAG rule change request seeks to promote the development of competitive markets for new technologies which are capable of servicing both regulated and unregulated markets (thereby providing for multiple revenue streams). The rule change request does not provide for specific changes to any one rule, instead COAG have proposed general changes to the classification of distribution services, specifically:

- Ensuring services from these technologies remain unclassified unless it can be established that the competitive market is unlikely to efficiently and effectively deliver the service; and
- Making changes to the classification process for distribution services including requiring the establishment of a guideline by the AER, provisions for reclassifying a service within a regulatory period and clear path for changing service classifications over time.

1.3.2 AEC Rule Change Request: Contestability of Energy Services – Demand Response and Network Support

Recognising competition to be the best mechanism for providing services to customers at an efficient cost, the AEC raised concerns with the NER and specifically a distributor or transmission operator's ability to directly invest in and procure DER 'behind the meter'. As a result, the AEC is seeking to clarify the issue by restricting DNSPs to the procurement of services of these assets from third parties or ring fenced entities only. To do so, the AEC has proposed the following:

- Restricting a network from using capital expenditure to provide certain services (introduction of a new service classification and require use of operating expenditure for contestable services only);
- Lowering the regulatory investment test for distribution (RIT-D) threshold to $50,000 (and shorten the process for such investments). Placing restrictions on non RIT-D approved expenditure rolling into the regulatory asset base; and
- Requiring publication of all relevant information creating a "level playing field".

By making changes to the service classification, both rule change requests seek to require distributors to procure certain inputs to regulated services from contestable markets, rather than having the discretion to invest in assets that may otherwise provide such inputs – thereby creating an opportunity to recover a regulated return in connection with such investments.

1.4 Structure of the Report

The following details the remaining structure of this report:

- Section 2 – Clarifying key terms
- Section 3 – Assessment framework
- Section 4 – Procurement of network support services
- Section 5 – Co-optimisation between multiple markets
- Section 6 – Network tariffs
- Section 7 – Distribution system operation
- Section 8 – Network access and connection
- Section 9 – Network planning and investment
- Section 10 – Non-distribution elements
- Section 11 – Key findings and recommendations
- Appendix A – ENA/CSIRO Roadmap
- Appendix B – Distribution system transformation.

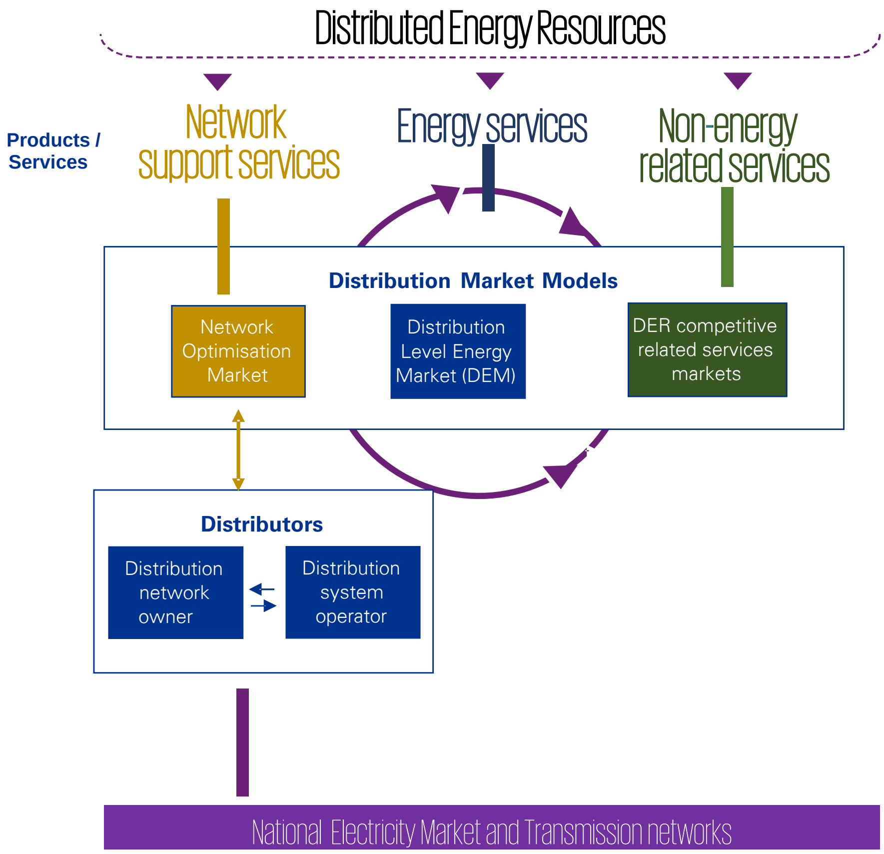
Readers are encouraged to read Appendix A before reading the body of the report if not familiar with ENA/CSIRO proposed Roadmap presented in their report issued in April 2017.

2 Clarifying key terms

It has become apparent through the release of various publications and through wider discussion within the industry that there is inconsistency in defining what is a DER in the context of a market, what a market for their products or services may look like, how this market would integrate with the wholesale energy market, customer appliances and finally what are the potential impacts to, and roles for, distributors moving forward.

This inconsistency in the discussion stems from the fact that there is no single market solution centred on a single DER technology, product or service. To avoid persistent confusion, KPMG has defined critical elements of the discussion as shown in Figure 3, having regards to the various definitions presented by other parties including those presented by the AEMC.

Figure 3. DER Products & Services and Market Models



2.1 Distributed energy resources definition

Distributed energy resources are generally defined as devices which are located at a customer premises and are able to inject power into the local distribution system (including embedded networks), such as embedded generation or battery storage resources, or which assist in the management of load at the premises.[17] These resources operate for the purpose of supplying all or a portion of the customer's electric load, and may also be capable of supplying power into the system or alternatively providing a load management service for customers.

DERs therefore could include such technologies as solar PV, combined heat and power or cogeneration systems, micro-grids, wind turbines, micro turbines, back-up generators and energy storage. Some parties may also consider demand response or energy efficiency to be a DER, given that they could in some circumstances have the same value as injecting power into the network.

There is currently some discussion as to whether the scope of the definition of DER should be limited to only those devices which can respond automatically to a remote signal which changes the energy flows (imports or exports) at the customer meter. A signal in this sense may be a control signal (e.g. a ripple control from the distributor) or a price signal (e.g. an energy spot price or a dynamic network tariff). Such a signal could come from a wholesale market, retail tariffs, network constraint conditions, commercial platforms, or other energy management algorithm.

This is the approach taken by the AEMC in its consultation paper.[18] For the purposes of this report, we do not consider it necessary to apply such a limited definition to the types of DER being considered. KPMG has been asked to consider how the role of distribution networks would best promote the efficient transactions of energy related products enabled by DER. As it is likely that owners of DER will want to seek to participate in multiple markets (wholesale, network and ancillary service markets), the distribution system will need to be managed and operated in a way that can accommodate these mixed interactions.

For example, a peer-to-peer transaction would be enabled by DER but may not be captured by the definition of DER applied by the AEMC. For this report, it is useful to be aware of all potential transactions enabled by DER.

We recognise that over time, the market will evolve to a high degree of automation for DER, as this will allow remote parties a level of control over the operation of the resource which will better enable DER to offer and capture the value along the electricity supply chain. However, automation is not a necessary condition for controllability as the DER owner could apply a separate operational system to the device.

Further, a degree of control over a DER may be considered a necessary precondition for the purposes of being procured by a DNSP for network support purposes.[19] However, we also note that a proportion of owners of embedded generation systems such as solar PV may not be inclined to actively participate in such markets.

Finally, multiple-use applications (MUA) are those where a single energy resource or facility, or a virtual resource formed as an aggregation of individual sub-resources, provides multiple services to several entities with compensation received through different revenue streams. DER could potentially provide and be compensated for many services targeted at three areas — customers, the distribution system,

[17] A device within a meter for example, a switch for a consumer's "controlled load" circuit that can be controlled remotely by a distributor is considered a DER. Such a device has an identical effect to a similar device located behind the meter (e.g. in the appliance itself), so it would create technological distortions to consider these two devices differently.
[18] Australian Energy Market Commission. Distribution Market Model. 1 December 2016.
[19] KPMG notes that the addition of a "smart controller" to an otherwise passive DER has the potential to turn this resource into a future market participant. This may have significant implications to the size of the market given the volume of rooftop solar PV installations already installed across individual distribution networks. Therefore, despite contributing to the technical issues experienced by the distributors in managing their network, they may equally form part of a longer term solution.

and the wholesale markets — as new markets and services evolve across the energy supply chain. "Virtual Power Plant" trials are a tangible example of such a development.

2.1.1 What technical challenges do they present?

The electricity distributor is responsible for providing non-discriminatory access to their network and for the safety and reliability of the local distribution system. These responsibilities involve regular reconfiguration or switching of circuits and substation loading for scheduled maintenance, isolating substation and distribution feeder faults, and restoring electric service. Under the NER, an electricity distributor must also ensure that local voltage, power factor and power quality are maintained within engineering standards.

An increased penetration of DER, particularly from renewable generation with its weather dependent intermittency and low stabilising inertia, will present four key technical challenges for management of the broader system (i.e. not only distribution related challenges)[20]:

- **Frequency control:** frequency control ancillary services (FCAS) are currently largely provided by synchronous generation to maintain frequency within prescribed operating standards;
- **Management of extreme power system conditions:** the ability of the power system to maintain frequency in response to a non-credible contingency event as those that recently occurred in South Australia in September 2016;
- **Visibility of the power system (information, data, and models):** the ability to effectively model the power system requires information and understanding of the electrical characteristics of all DER components of the power system that can have a material impact on its dynamic behaviour; and
- **System strength:** a reduction in system strength has been observed in certain parts of the power system as the generation mix has changed. This is a new term developed to refer to situations where there is a low voltage level.

While DER, particularly from renewable energy generation, is currently imposing technical challenges for power system security, as noted previously, other forms of DER have the potential to mitigate them, including energy storage, electric vehicles, home energy management systems and demand management systems for commercial and industrial (C&I) consumers.

2.2 DER products and services definitions

The term "distribution market model" or "DMM" first appeared in the AEMC consultation paper as an all-encompassing definition for distribution-level markets for the provision of DER-related products and services. While this broad definition is appropriate for the purposes of the AEMC's consultation paper, it pays to delve deeper and understand what these potential markets may be and what products or services may be contracted/traded in them.

In principle, there are three[21] different types of related products / services (and therefore markets) which may be derived and traded from DERs. For the purposes of this report we have organised these markets into the different uses by participants, notably the difference between use by distribution networks (which could be considered to be regulated as it will be paid by regulated revenue) and other commercial value from DER.

[20] AEMO, Future Power System Security Program Progress Report, August 2016, page 4
[21] KPMG also notes a large proportion of DER value is not traded at all, but realised by the customer through self-consumption and home energy management.

- ***Energy Services:***
  - As per the wholesale electricity market, albeit on a smaller scale, a DER may contract/trade its energy production for example via direct contracting with peers (peer-to-peer transactions), third parties, aggregators or through a more sophisticated trading platform bringing together many buyers and sellers with market clearing and settlement. In certain instances, purchases of energy from DER may be used to hedge against pool price exposure and/or broader portfolio management.
  - Similarly, customers may offer their ability to reduce/adapt their consumption patterns for particular time periods. This could be done automatically (via remote technology) or via the customers making active decisions or assigning controllability rights to a third party in response to market outcomes. These services would effectively result in a reduction in demand for defined periods of time on certain days.

- ***Network support services:***
  - Various DER's may provide network support ancillary services including voltage control, frequency control and reactive power. As per the ancillary service markets supporting the bulk supply system, a market for the provision of ancillary services may be developed. These services would be provided for defined periods of time across certain days, or under certain market conditions. These services may be attractive to networks as alternatives to network reinforcement or generators with existing contractual commitments.
  - Other forms of network support include network deferral or short term operational support.[22]

- ***DER competitive related services:***
  - This terms applies to any non-energy related DER service which is not transacted with distributors as a network support service (e.g. frequency control to market operator).

We also recognise the interactions between the uses of DER. For example, while a DNSP procures DER for network support, a retailer at the site will also have value in understanding such transactions, that it may not be a direct party to, in order to assist it in hedging its customers' aggregate load. The relative value of the DER services to different market participants will impact on the importance of the role of DNSPs in achieving efficient use of DER.

Energy and network support services may include **"optionality**" where participants have the contractual right (or option) to access DER capability or where demand response at future dates could also be traded across a platform. This could be in the form of different derivatives (i.e. forwards, futures, swaps) and would assist participants to manage their exposure to the market (e.g. through hedging a position) and fulfil their energy supply obligations, providing for greater flexibility and optionality relating to the products traded.

It is not necessary for all these types of products to be traded on the same platform. Different markets may emerge depending on the nature of the transactions and the characteristics of the buyers and services. Other than these services, customers will also benefit from the reliability value and retail tariff savings from owning DER. The proportion of these benefits to the value gained from trading DER products will determine the importance of facilitating DER transactions.

[22] In addition to energy, a DER may provide NSS whereby a DER is capable of changing its energy flows at times that are of value to the distributor in maintaining service reliability. These services may be provided for defined periods of time across certain days, or under certain market (network loading) conditions. These services may be attractive to distributors as an alternative to network reinforcement or generators with existing contractual commitments.

2.3 Distribution market model definitions

It is possible that different DER markets will emerge over time. In all cases, a well-functioning market will be dependent on the capabilities of technologies connected to the distribution network and the frameworks established to facilitate the market. There remains a high level of uncertainty regarding the structure of these markets and how they will integrate into the broader electricity supply system. Two possible markets include a distributed energy market (DEM) and/or a NSS market – both described in further detail below.

2.3.1 Distribution energy market

A DEM is a market platform for trading of electricity at or between points on the distribution network, including customer connection points, distributed generator connection points, interconnection points with transmission networks or internal nodes or hubs on the distribution network (physical or virtual).

Market participants will vary depending on the products traded, type of exchange platform established and the structure of legislative and regulatory frameworks implemented (if at all). Specifically, market participants may include, but not be limited to:

- residential and commercial investors in DER seeking to sell excess energy capacity back to the grid;
- retailers seeking new product offerings or access to alternative energy supply or demand response sources;
- generators sourcing potential optionality to mitigate future physical or financial risks;
- transmission network service providers (TNSPs) sourcing grid support services;
- distributors; and
- third parties, such as demand aggregators, capable of offering load control or demand response services to the market.[23]

The development of a new market presents a number of critical design (and policy) related questions. Box 1 below presents a sample of these questions in relation to a DEM, while this report explores some of these questions in greater detail.

Another form of market that may evolve is retailer-facilitated trading (e.g. virtual net metering). Different retailers might run their own competing platforms concurrently – so it may not be a single platform and each retailer could determine their own market design elements. The DEM and these other markets will raise similar design questions.

2.3.2 Network support services market

A network support services market provides for the contracting / trading of NSS as an input into the provision of distribution services.[24] In this scenario, a distributor may be considered a monopsony buyer of NSS provided by DER given its role in investing, operating and maintaining its distribution network. Potential trading intermediaries (e.g. aggregators) may also participate, and can be thought of as buyers who package energy and demand response from DERs to provide NSS to a distributor. These services are valued by a distributor at times of managing network reliability and may afford an alternative to

[23] Aggregators act to create a virtual power station by pooling or "aggregating" various existing onsite standby generation plants (i.e. small scale distributed generation) capable of offsetting site demands or businesses willing to practice load-reduction in times of critical need on the network.
[24] As the ENA/CSIRO highlight in their Roadmap, it is possible a NSS market will not occur via a facilitated / digitised platform initially, but rather through bi-lateral negotiations with consumers and other market actors.

network capital expenditure solutions or existing contractual commitments with generators. Therefore, a NSS market would cover procurement of DER for both a long term alternative to network investment and a short term ancillary service to support grid operations.

The ENA/CSIRO model provides a high-level approach to development of a market for NSS, as discussed in Section 4.2 and Appendix A.

Box 1. DEM Design

As with any proposed distribution-level market, there are a number of fundamental design questions which need to be addressed as part of the development process. In considering a DEM design, these would include, but not be limited to:

What technologies and who qualifies for participating in the electricity market? As new technologies become established in the market, and existing technologies continue to improve, their ability to participate in a DEM will need to be assessed.

What products are traded and how are these products defined? If the product is *not* locationally-specified, the DEM may not contain the information or tools that a distributor requires in order to manage network flows.

What is the minimum capability and service performance for DER? For participants transacting in the DEM, specific (minimum) capability and performance standards associated with the provision of services are to be met.

Is participation mandatory or optional? Must all energy flows be traded through the DEM? If a retailer uses a DER to supply its customers, does it need to sell this generation in the DEM and then buy it back from the market? If optional, DEM outcomes could represent only a portion of network flows and therefore may not provide useful information for the distributor.

Who would be responsible for balancing the market? How the markets are settled, allowing for new market entrants and ensuring accurate billing and payment will need to be considered in the overall context of the market.

2.4 DER competitive related services markets

DER competitive related services is a broad term which applies to any non-energy related DER service which is not transacted with distributors as a network support service (e.g. frequency control to market operator). These services are likely to be incremental to the energy related services and could be traded on the same platform.

2.5 Role of a distributor

DERs “present both opportunities and challenges for distribution network businesses”.[25] These opportunities and challenges are compounded as technology costs decline allowing for wider penetration across Australia’s distribution networks. While new opportunities and challenges are

[25] Australian Energy Market Commission. Distribution Market Model. 1 December 2016.

created, the core or traditional roles performed by a DNSP will continue to be essential to the overall operation of the system. These roles include, among others, planning, investment, operation and maintenance of the distribution network ensuring for continued system security, safety and reliability of supply.

What is unclear in this future state is who would have responsibility for these roles and how these roles would interact with a distribution-level market should one be established.

To understand the role or function of a DNSP and their potential interaction with a DER market, we have broken their core roles into two, namely:

- as a **distribution network owner** (DNO) responsible for building, maintaining and owning the network. It effectively leases the optional control of its network assets to a distribution system operator (DSO), receiving payment from the DSO for the use of those assets. A DNO effectively becomes a passive asset owner; and
- as a **distribution system operator** responsible for the provision of reliable distribution services, including transporting of energy between points on the distribution network, customer connections and interconnections with the transmission network. In effect, the DSO manages the distribution network operationally, and is responsible for switching of network assets and providing instructions to NSS providers. Further, the DSO is responsible for setting network tariffs, and charges the financially responsible party at each connection point for distribution services, based on the energy flows metered at the connection point.

  A DSO would be responsible for procuring network capacity and network support services as needed. This responsibility presents a number of issues in relation to the role a DSO may have in a distribution-level market and importantly its on-going participation in that market.

In Australia, these roles are currently integrated within a single distributor.

2.6 Role of a retailer

The role of a retailer will evolve as we see new markets for DER products and services established throughout the broader network. For the purpose of this report, any reference to a retailer is to the financially responsible party for a customer connection point which has the following roles:

- Financially responsible party for energy consumption at a customer connection point;
- Pays distribution charges to the DSO for this point;
- Makes or receives payments based on metered energy flows at this point;
- Supplies the retail customer with electricity and other services according to their retail contract; and
- Bills the retail customer for those services and provides different payment channels.

3 Assessment framework

This section presents our analysis of "six key elements" of the market and regulatory arrangements where the actions and behaviour of the DNSP will influence the efficiency of DER investment and operation and the development of a long-term, competitive market in DER products and services. For each of the key elements, we develop a list of optimal characteristics and outcomes which we apply as the assessment principles for evaluating existing frameworks (and the Roadmap's proposed arrangements).

In defining these principles, we have built on the principles proposed by the Council, the principles proposed by the AEMC and the Roadmap's Balanced Scorecard. Where relevant, we have also included in our assessment the Grid Neutrality Principles developed to promote a more open grid and facilitate the increase in DER. Overall, we have sought to develop a list of principles consistent with achieving the NEO.

3.1 Elements within DER market arrangements

The current roles performed by a DNSP will create a number of opportunities for interaction with consumers (and other market participants) with DER. As explained above, our approach has been to identify individual elements (as shown in Table 1) where the DNSP will interact or engage with DER.

Our report is organised to step through each element and assess the risks to efficient use of DER resources and the promotion of a long-term, competitive market in DER products and services under a scenario of high DER deployment. For each element, we also attempt to identify potential regulatory responses and market design principles for consideration in further discussion regarding the development of a competitive DER market.

Table 1. Elements of DNSP and DER interaction

Element	Description
Procurement of NSS	It may be efficient for a DNSP to procure DER as a NSS in order for it to maintain the safe, secure and reliable operation of the network. In doing so, a DNSP may procure these services directly from a consumer with DER or market actor (such as a third party aggregator) through a competitive procurement process, or through a market platform into which participants with DER may offer.
Co-optimisation between multiple markets	The development of multiple commercial trading platforms for DER will result in greater complexity in how DER-related products and services are utilised and managed in the market more broadly. Depending on the type and level of sophistication of platforms established, the products or services traded and the ability for participants to access or participate in specific markets, these markets will have implications for not only how a DNSP manages their network but also how DER owners maximise the value associated with their assets. It is imperative the outcomes across these markets are co-optimised in order to maximise the value associated with individual (or grouped) DER assets.
Network tariff setting	DNSPs are currently responsible for setting network tariffs, subject to the approval of the Australian Energy Regulator (AER). These network tariffs may provide price signals to investors to purchase new DER or change the way they operate existing DER. Further, through application of a "smart controller", a DER may be designed to respond to network tariffs. If a retailer controls a DER, it will see network tariffs directly, while a consumer controlled

Element	Description
	DER will only see network tariffs to the extent these are passed through by retailers.
Distribution system operation	Traditional roles performed by a DNSP will continue to be essential under a high DER scenario to the overall operation of the system. Where a DNSP remains responsible for the operation of the system, it may impede the delivery of DER services through its decisions on system operation. For example, a DNSP might be permitted to prohibit certain market outcomes such as those that imply a demand for distribution services in excess of its capacity to supply them. This is analogous to AEMO placing transmission constraints on wholesale market outcomes. This would have flow-on impacts to the offer of services in the wholesale market. Currently, DNSPs do not actively manage their system operation but they may need to do so if flows become more complicated across the network.
Access and Connection	The DNSP is responsible for connection and access arrangements available for DER in accordance with Chapters 5 and 5A of the NER. While a DNSP must be provided with the ability to manage its network ensuring for safe, secure and reliable operation, it must do so in a fair, transparent, and non-discriminatory manner providing for efficient connection of DER resources.
Network planning and investment	A DNSP in its network planning role would be best placed to identify the network value (accounting for potential contract costs) of a DER product or service, and the best locations for the service. Further, depending on the level of interaction with a market, it is possible for a DNSP to acquire information in relation to the operation and/or behaviour of individual market participants with DER and/or outcomes of a DER-related market more broadly.

The Council has also asked us to have, at a high level, regard to non-distribution elements of the market arrangements where these could complement or impact on the interaction between DER and a DNSP. These elements, described in Table 2, are discussed further in Section 10.[26]

Table 2. Non-distribution elements of DER interaction

Element	Description
Non-distribution elements	
Access to wholesale energy market	While the size of any one DER will preclude a consumer from participating in the wholesale energy market, the role of a retailer, aggregator or other third party (collectively referred to herein as "aggregator") may present an opportunity for them to participate on behalf of a consumer instead. In this instance, the aggregator would combine multiple DER assets to form a portfolio, and sell the products or services derived from that portfolio into the wholesale energy market (e.g. capturing high spot prices) or, where possible, as an ancillary service to the Australian Energy Market Operator (AEMO).
Peer-to Peer trading	The growth of peer-to-peer frameworks, where customers can buy and sell electricity directly from each other, are having a transformative effect in other sectors. A peer-to-peer service for DER has the potential to raise considerable new challenges for regulators and policy makers, particularly, where multiple services (platforms) are established targeting specific technologies or participants. There are considerable unknowns associated with the future advances in both DER and supporting technologies (including platforms), and consumer preferences for managing their energy supply.

[26] This table does not represent a full assessment of all potential elements to be considered in the design of a DER market. In addition to those listed in table 2, the following additional elements warrant broader consideration and are considered beyond the scope of this report, such as Metering and Settlement. These elements are not considered as part of the Roadmap.

3.2 Key principles for future market and regulatory design

To aid in our critique, and to build on the work of the AEMC and ENA/CSIRO, KPMG has provided for an expanded list of principles of good market and regulatory design specific to the future operation of a competitive and efficient DER market(s). These principles represent our view of what will be required in order to achieve the NEO, and market efficiency more broadly, in the provision of DER related products and services. KPMG has mapped each principle to those elements whereby a DNSP may interact with a consumer (or other market participant) within a DER market as discussed above.

Table 3. KPMG proposed principles of good market and regulatory design

Element	Principles to promote efficiency and competition in DER
Distribution elements	
Procurement of NSS	• DNSPs have the ability to utilise DER for network support (especially as network tariffs may not deliver a required customer response) • Payment for NSS compensates the risk adjusted value derived by the DNSP • There is a transparent and credible methodology on how the DNSP calculates the prices for DER services • Clear and effective operational procedures and boundaries have been established in relation to how a DNSP may use DER • A DNSP is prevented from taking advantage of its position as single buyer of NSS • Risk of non-compliance associated with DER is allocated to the party who is best able to manage that risk
Co-optimisation between multiple markets	• The onus of decision-making on how DER is utilised across buyers is with the owner of DER or a third party (where contracted) • Any potential conflict between market operators (MO) and DSO are transparently managed (e.g. through an information exchange) • Clear separation of responsibilities between MOs and DSO • Orchestration of DER services across multiple markets is achieved in a manner consistent with efficient outcomes
Network tariff setting	• Provide compensation for network value delivered by DER • Promote efficient investment in DER • Allocate costs based on use and causality • Customers are provided with tariffs which they understand and are able to respond to • Alignment of risks and rewards
Distribution system operation	• Responsibilities for the safety and reliability of the local distribution system are clearly specified, transparent and allocated to the most appropriate party • A DSO is to meet the needs of network users at the lowest long-run cost, and the regulatory framework has been designed to achieve this objective • Conflicts of interest between the DSO role and related business roles (particularly that of DNO) should be avoided or managed

Element	Principles to promote efficiency and competition in DER
Access and Connection	• Access to the network is on an open and non-discriminatory basis; • Connection and access standards are fair, transparent and promote efficient deployment and use of DER[27] • Network access and connection policies do not unduly constrain the ability of DER to deliver a full range of services • Access and connection requirements support operation of commercial market platforms
Network planning and investment	• DNSPs will select the most efficient solution irrespective of whether it is a network or non-network solution • Role of the distribution network is to meet the needs of customers (customer centric) through facilitating physical electricity flows that support customer transactions • Networks must not impede competitive markets and therefore provide adequate hosting capacity where efficient[28] • Networks provide access at a reasonable cost in accordance with their regulatory obligations[29]
Non-distribution elements	
Access to wholesale energy market **Peer-to-peer trading**	• Retailers, aggregators and other third parties should be provided access to wholesale energy markets where sufficient DER scale is achieved[30] • Decisions with respect to how DER is utilised across markets (wholesale, DEM/NSS or other) is with the owner of DER or third party (where contracted) • Information exchanged between markets is done so transparently, mitigating any conflicts • Individual trading platforms provide technology neutral access for all participants.

KPMG has used the above elements and principles to review the current regulatory arrangements governing the sector (and proposed changes under the Roadmap) in providing for a competitive and efficient DER market. As part of our assessment, we have identified gaps and potential barriers or risks to achieving optimal market outcomes, including efficiency in terms of both investment and operation of the electricity market moving forward, while contributing to the overall reliability, safety and security of the national electricity system.

3.3 Assessment considerations

The assessment principles (described above) have been informed by the following work in review of future market models for DER-related products and services, shown in Figure 4.

[27] Grid Neutrality Principle 5 – Foster open access to the grid
[28] Hosting capacity is the amount of capacity on any given portion of the distribution system to accommodate additional DERs with existing and already-planned facilities. This is no different from conventional network capacity (i.e. import capacity): the DNSP should provide sufficient capacity to meet reliability standards. That begs the question of what is the reliability standard for export capacity.
[29] Grid Neutrality Principle 1 – Empowering the customer while maintaining access at reasonable cost
[30] Subject to meeting the relevant licence and registration requirements

Figure 4. Assessment principles considered

3.3.1 Australian Energy Council proposed principles

The Council considers that the following are necessary attributes of an efficient market or distribution platform capable of accommodating increased uptake of DER:

- Consumer choice should drive the development of markets;
- Competition should be promoted to the extent possible – not only does this enable choice, it is also the best driver of cost efficiencies, and the process of discovery that is necessary to determine what value propositions/services consumers will respond to;
- Regulation should only be used where necessary to address market failure (and even then only when it is clear that the costs/distortions of the market failure exceed those associated with intervening);
- Risks should be allocated to parties that are best able to manage them;
- Particular technologies should not be favoured over others (i.e. technology neutrality);
- Networks should not be permitted to directly participate in the supply of services that could otherwise be provided by competitive markets;
- Networks should provide an open access platform for the deployment of DER and development of associated products and services;
- The market should determine the highest value use/deployment of DER, i.e. it should not be determined through a regulatory process; and
- The regulatory framework should not constrain the expansion of additional services through DER, e.g. peer-to-peer trading.

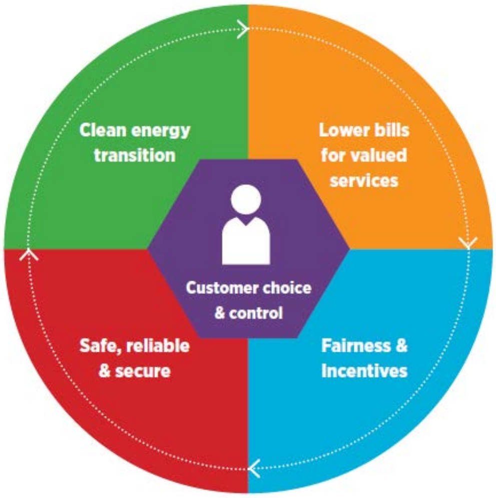
3.3.2 ENA/CSIRO Balanced Scorecard

While the ENA/CSIRO do not explicitly reference the NEO or their own suite of design principles, they do present a 'Balanced Scorecard' approach (as shown in Figure 5) to measuring the long term customer outcomes to be captured as part of its Roadmap for transforming the energy network.

This scorecard sets out the high-level objectives to be achieved as a result of the study undertaken by the ENA/CSIRO and is supported by specific milestones to be reached over the assessment period. Similarly to the AEMC, the scorecard (and milestones) does not fully address the fundamental market design elements / principles required in designing a DER market.[31]

[31] The Roadmap looks beyond simply a market for NSS and provides a pathway for wider change to the operation and governance of the national electricity market.

Figure 5. ENA/CSIRO Balance Scorecard[32]



Instead, only certain elements are expanded upon by the ENA/CSIRO such as those "architectural principles" required from a potential system supporting a NSS market:

- Coordinated and self-optimising: The system must seamlessly enable distributed energy resources' fleet 'orchestration' and self-optimisation at the customer level;
- Technical and economic benefits: The system must enable the integration of distributed energy resources in a way that supports both power system reliability and economic efficiency;
- Firmness of response: The system must be designed to ensure firmness of response from distributed energy resources at all critical times (with equivalent certainty to traditional network augmentation where it is relied on to avoid that expenditure);
- Non-discriminatory: The system must provide for non-discriminatory participation by qualified participants;
- Transparent: The system must ensure that the value of network optimisation opportunities is transparent and the benefits are received for actual distributed energy resources services provided;
- Verifiable: The system must be observable and auditable at its interfaces; and
- Future proof: The system must be scalable, adaptable, and extensible across a number of devices, participants, and geographic extent.

3.3.3 AEMC Distribution Market Model – Approach Paper

A high penetration of DER across Australia's electricity networks creates transformative opportunities in relation to how our networks are planned and operated. This transformation has and will continue to see investment in new infrastructure and technologies, changes to existing regulation and the formation of new business models. Further, we are beginning to see new markets appear in relation to these changes for DER products and services.

[32] Energy Networks Australia and Commonwealth Scientific and Industrial Research Organisation. Electricity Network Transformation Roadmap" Final Report. April 2017

With these changes, a number of questions are raised with regards to the capacity of the current legislative and regulatory framework to facilitate this transformation and, importantly, the ability of this framework to continuously achieve the NEO, which is:

> *"To promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to – price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system."*

To frame its own assessment of the technical and regulatory challenges resulting from DMM and the ability of existing frameworks to achieve the NEO, the AEMC is to be guided by the following principles of good market design outlined in their recent DMM consultation paper:

- Facilitate effective consumer choice;
- Promote competition where feasible;
- Regulate to safeguard the safe, secure and reliable supply of energy, or to address a market failure;
- Promote price signals that encourage efficient investment and operational decisions;
- Ensure technology neutrality; and
- Prefer simplicity and transparency.

These principles provide for a high level approach to designing a DER market, consistent with good regulatory practice. However, they are not targeted to the specific issues or elements to be captured within that design.

3.3.4 Grid Neutrality Principles

A report titled "Five Principles for Tomorrow's Electricity Sector" and published by the Public Utilities Fortnightly in October 2015, recognises the need for "grid neutrality" in guiding future transformation of electrical systems/networks.[33] The authors recognise that the historic "one-size fits all" model adopted thus far is no longer relevant for today, given changes in:

- Needs – a shift in focus towards optimisation of existing infrastructure, as opposed to simply building new infrastructure;
- Technology – continued penetration of DER, of smaller scale and modularity are now plausible solutions to meeting the needs of consumers and the network (at potentially a lower cost); and
- Consumers – are now more sophisticated in managing their energy use and are becoming "prosumers" supplying the grid with energy, capacity and ancillary services.

The grid neutrality principles are defined to "safeguard a network's underlying communal infrastructure" while providing a foundation upon which to assess future developments in relation to the network. The principles maintain the existing requirements to provide access to safe, reliable energy services at reasonable cost, and build upon this by introducing a requirement to maintain the neutrality of the network. The five grid neutrality principles are[34]:

1. **The Consumer Empowerment Principle** – Empower the consumer while maintaining universal access to safe, reliable electricity at reasonable cost. Maximise consumers' ability to achieve their individual energy needs and the needs of the grid without compromising the universal right of all consumers to access a safe, reliable energy service at reasonable cost.

[33] Jenny Hu, Shayle Kann, James Tong & Jon Wellinghoff, *Five Principles for Tomorrow's Electricity Sector*, Public Utilities Fortnightly, October 2015.
[34] Ibid.

2 **The Commons Principle – Demarcate and protect the "commons".** Establish clear operational and jurisdictional boundaries for public and private interests.

3 **The Risk/Reward Principle – Align risks and rewards across the industry.** Allocate financial risks to stakeholders who are most willing and able to assume them. Safeguard the public interest by containing the risks undertaken by private parties to those participants.

4 **The Transparency Principle – Create a transparent, level playing field.** Promote and protect open standards, data access and transparency to encourage sustainable innovation on the grid. Prevent any single party — public or private — from abusing its influence.

5 **The Open Access Principle – Foster open access to the grid.** Allow all parties who meet system-wide standards the opportunity to add value to the grid. Apply all standards evenly and prevent any non-merit-based discrimination.

4 Procurement of network support services

This section considers the design of the mechanisms that a distributor may use to procure NSS from the owners or controllers of DER. Therefore, a NSS market would cover procurement of DER as both a long-term alternative to network investment and as a short-term ancillary services to support grid operations.

Key findings

1. Direct procurement from customers creates risks and issues for both the owner of DER and also to market efficiency. The materiality of these risks will vary over the different stages of market development and the level of DER deployment:
    a) There is potential for a DNSP to under-pay the DER owner the associated network value. This is a reflection of the DNSP being the single buyer of network support services and is complemented by the cost minimisation incentives under the existing economic regulatory framework. The current lack of transparency on the potential network value from DER adds to this risk. By contrast, the competitive dynamic inherent in the energy market should drive up the value offered to customers.
    b) The prospect of a DNSP directly procuring network support from the DER creates issues of enforcement and compliance, and this may require a means to financially penalise the DER if it fails to comply. For example, a DNSP could potentially pass through any loss of revenue under the Service Target Performance Incentive Scheme (STPIS) for the DER's non-compliance. In addition, the DNSP having the direct means to control the technology may prevent the DER owner from accessing other revenue from competitive DER-related products. Retailers or other intermediaries might create more flexible risk management options in this context, resulting in greater utilisation of DER.
    c) Some consumers may not have the means, or the ability, to fully understand and evaluate any offer from a DNSP for network support. There is a risk that consumers will not make an informed choice. Given their vast experience in dealing directly with consumers on complex energy matters, retailers might be better placed to work directly with consumers to help them better understand these issues. While this may be an issue to all forms of DER procurement, there may be additional confusion from a DNSP attempting to procure directly from customers given existing relationships.
    d) To procure directly from customers will require the DNSP to develop its own products and solutions in order to offer them to customers (such as the existing load control products). This could create a further barrier to other competitive products if the DNSP is inclined to look more favourably on the products it has developed and with which it is familiar (and less favourably on products developed within the competitive market, such as those developed by retailers or other third parties). A DNSP will tend to have a greater understanding of what its own products can offer and the associated risks, and can design those products to match its own preferences. Nevertheless, DNSPs should be encouraged to utilise the most efficient source of DER, whether it is sourced in-house or from customers or via third parties.
2. It is not clear if DNSP procurement will provide long-term certainty for DER owners over the investment life under the current economic regulatory framework given the five year regulatory control period. However, this may not be an issue given that a considerable amount of DER investment may be driven by personal circumstances (e.g. better management of electricity bills).

4.1 Current arrangements

The current arrangements facilitating the provision of NSS display both intrinsic and contingent features. The former are fundamental to how the energy and distribution markets operate. The latter reflect a legacy of pre-DER concerns and decisions but are not necessarily desirable or optimal to DER in the future.

The following may be categorised as intrinsic features of the current mechanisms:

- The provision of distribution services is a natural and regulated monopoly and will remain so in the future where the DSO arm of a DNSP is responsible for the delivery of these services. The AER in its assessment of the revenue requirements for a distributor will primarily treat NSS as operating expenditure where procured from other parties. While NSS is a key input to the provision of distribution services, it has no value to parties not involved in the provision of these services.

  As a result a DSO is a monopsony buyer of NSS on its network.

- In order to minimise the costs of distribution service provision, the DSO should be able, and is encouraged, to procure NSS in a way that drives down costs over the long-term. Under this condition, the costs associated with procurement of NSS may only be considered efficient where there is otherwise a limitation on the network, or a system security issue, that may not be able to be resolved by the market itself (i.e. changes in customers' demand).
- Retailers act as consumer gateways to the wholesale energy market, offering a packaged retail offering of "delivered energy" which combines wholesale energy (purchased from wholesale energy markets) and distribution services (purchased from the DSO). This packaging means that the retailer is the consumer's sole supplier in terms of grid-supplied services.

  Depending on the design adopted by future market mechanisms, this role currently played by retailers, may no longer be the sole source of grid supplied services for consumers.

- NSS delivery involves changes to consumer load (or exports) at the time required by the DSO, meaning that NSS delivery affects the wholesale energy charges paid by retailers and the retail energy charges paid by consumers.

  In short, NSS delivery unavoidably has a financial impact on retailers and consumers. Depending on the individual scenarios of consumers and retailers, this impact may be positive or negative.

- DSOs are prohibited from supplying consumers with energy or, more generally, from trading in the wholesale energy market. This is to prevent conflicts arising between distribution service provision and energy market participation.

The following represent contingent features in the current mechanisms:

- DSOs are currently fully integrated with DNOs within DNSP businesses;
- DSOs, to the extent that they purchase NSS, primarily do this directly from consumers either via direct offerings (e.g. such as smart air-conditioner discounts) or by bundling NSS procurement with distribution tariff service products specifically, as a "controlled load" service;
- DSOs own and operate control systems which give effect to these services; these are the only such control systems currently in existence, except for a few pilot programs (discussed below);
- DSOs are subject to statutory reliability standards, which in some cases are specified in a deterministic way referencing the network assets that help to deliver that service; and

- DSOs are also subject to financial reliability incentives, such as STPIS, which attempts to establish an additional probabilistic reliability standard, together with financial incentives for maintaining or exceeding this standard.

Historically, DNSPs have procured NSS directly from consumers through their "controlled load" distribution service offering.[35] Under the "controlled load" service, a DSO is entitled to switch on or off a circuit in a consumer's premises, on which the consumer has connected devices that it is happy to be controlled in this way, such as hot water heaters and pool pumps. The DSO controls these switches in a way that helps it to manage its network and thus provide reliable distribution services. In return for relinquishing this control, a customer will receive a lower distribution usage tariff which is passed on by the retailer. Under the current arrangements, there is no means to verify or assess whether the reduction in network tariff compensates for the network value provided by the load control.

Finally, under this approach, there is no scope (or incentive) to use the control mechanism for energy market cost management, which may be a higher value use under certain circumstances. For example, in South Australia, hot water load has been considered to cause wholesale price spikes and voltage control issues for AEMO in managing load across the system. The potential mis-alignment between network value and use of DER and the other market impacts is an issue arising in the context of procurement of DER by DNSPs under a high DER scenario.

4.2 ENA/CSIRO Roadmap

To provide for a customer orientated network, consistent with its balanced scorecard objectives, the Roadmap describes the development and use of Advanced Network Optimisation (ANO) tools to assist with distribution planning and operation and a NOM through which a distributor may procure network support services from third party suppliers, including DERs.

Specifically, this market is to provide for a technology neutral mechanism for procuring NSS only where and when required. The ENA/CSIRO have identified that such a market mechanism may be simplistic in its early adoption, for example where distributors contract directly with consumers and/or market actors for the provision of NSS. As processes and technologies mature, this market is expected to move to a more sophisticated digital platform (referred as a digital Network Optimisation Market (dNOM)) providing for greater automation and real time network optimisation services and perhaps support a range of other energy innovations.[36]

Importantly, the ENA/CSIRO note that the "procurement model should be justified by value created. There is value in retaining optionality as to the ultimate form of the Network Optimisation Market, including assessing whether the benefits of digital platforms outweigh the costs."[37]

The ANO tools and NOM are to be integrated in their functionality, whereby the ANO tools identify the need for NSS while the NOM sets out the method for procuring those services from the market.

[35] Strictly speaking, it is not the consumer who buys the distribution service but rather the retailer, who is responsible for paying network tariffs. In this sense, the "controlled load" NSS is purchased from the retailer rather than the consumer, directly. Whilst strictly true, this is unhelpful. It is the consumer who has in the past decided on the controlled load service and arranges for the DSO to configure and meter its controlled load circuit accordingly. The retailer is then presented with a fait accompli: that part of the consumer load is on a "controlled load" service. So, whilst it pays the bills, the retailer has no involvement in the decision making that lies behind the transaction. To all intents and purposes, the DSO has purchased directly from the consumer.
[36] Energy Networks Australia and Commonwealth Scientific and Industrial Research Organisation. Electricity Network Transformation Roadmap Final Report. April 2017.
[37] Ibid.

Importantly, the NOM would only procure non-network support services. A distributor may continue to meet its needs internally through building / reinforcing its own network or through the development of non-network options itself.

The Roadmap provides for a phased approach to establishing these tools and markets with basic NOM functions established immediately. Over the first half of the assessment period, ANO functions (planning, operation, intelligence and control) are introduced and slowly integrated with the functioning of the NOM. By the end of the assessment period, a feasibility study, cost benefit analysis and conceptual design of a dNOM is complete. The table below highlights the key milestones set by the ENA/CSIRO to establish ANO tools and a NOM.

Table 4. ENA/CSIRO Roadmap Grid Transformation and Network Optimisation milestones

Foundation Phase (2017-2022)	
Grid transformation	**Network optimisation & platforms**
Milestone 1: By 2018, the approaches and protocols to address the management and exchange of information between networks and distributed energy resources participants and to allow effective coordination of the system in real time and supports full interoperability are determined. By 2018, the approaches and protocols to address the management and exchange of information between networks and distributed energy resources participants and to allow effective coordination of the system in real time and supports for full interoperability are determined. These approaches would be established with the highest levels of security including data management, information privacy and cyber security.	**Milestone 1:** By 2018, networks with very high distributed energy resources levels are implementing basic NOM functions to procure locational distributed energy resources services for network support, either directly from customers and/or through their agents.
Milestone 2: By 2019, an integrated suite of advanced network planning models, techniques and distributed energy resources services valuation methods have been established as foundational to the mainstreaming of distributed energy resources services as non-network alternatives **Milestone 3:** By 2019, an integrated suite of distributed grid intelligence and control architectures and tools have been agreed as foundational to the safe, reliable and efficient operation of a high distributed energy resources distribution system	**Milestone 2:** By 2019, a basic set of Advanced Network Optimisation (ANO) functions are performed where networks with very high distributed energy resources levels progressively implement advanced network planning tools, distributed grid intelligence and control and advanced network operation techniques.
Milestone 4: By 2020, an integrated suite of advanced network operation mechanisms and tools have been agreed as foundational to the safe, reliable and efficient operation of a high distributed energy resources distribution system which also contributes to overall power system security. **Milestone 5:** By 2022, the full suite of Advanced Network Optimisation (ANO) tools have been trialled and validated across a diversity of Australian network topologies and DER "scenarios". **Milestone 6:** By 2022, undertake R&D activities to identify solutions for identified technological gaps in the current Australian power system.	**Milestone 3:** By 2020, collaborative projects demonstrating the integration of Advanced Network Optimisation (ANO) functions and NOM procurements have validated direct and market based orchestration of distributed energy resources as a reliable non-network alternative.

Implementation Phase (2023-2027)	
Grid transformation	**Network optimisation & platforms**
	Milestone 4: By 2023, networks with very high distributed energy resources levels are performing an integrated set of Advanced Network Optimisation (ANO) functions and NOM procurements as mainstream activities to ensure technical stability, economic efficiency and market animation.
	Milestone 5: By 2027, a feasibility study, cost benefit analysis and conceptual design of a digital Network Optimisation Market (dNOM) is complete.

The ENA/CSIRO recognise there are several factors which may influence the development of a NOM. This is recognised by the ENA/CSIRO who note:

> *"The work package does not necessarily result in the final outcome for the network optimisation (NOM). It specifically includes a review process that will establish the ongoing vision for the best long term approach given the experience gained from the incrementally based development process, and the environment that exists at the time. The completion of a rigorous business case will provide certainty regarding the future direction and avoid any development that cannot clearly be shown to be beneficial. It could be expected that the development of platforms and the potential for additional services and roles to be developed in line with further industry change will be an ongoing process that may require periodic revision of the vision and further business case assessment."*[38]

4.3 Key principles for future market and regulatory design

As per our assessment framework (described in Section 3), KPMG considers the following market and regulatory design principles in relation to the procurement of DER products by DNSPs for network support necessary in order to achieve market competitiveness and efficiency for DER-related products and services:

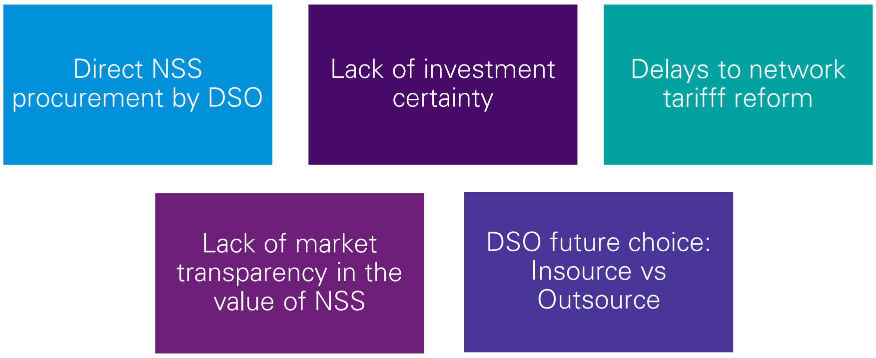
- DNSPs have the ability to utilise DER for network support, especially as network tariffs may not deliver the required customer response;
- Payment for NSS is compensative of the risk adjusted value derived by the DNSP;
- There is a transparent and credible methodology on how the DNSP calculates the prices for DER services;
- Clear and effective operational procedures and boundaries have been established in relation to how a DNSP may use DER;
- A DNSP is prevented from taking advantage of its position as single buyer of NSS; and
- Risk of non-compliance of DER allocated to the party who is best able to manage that risk

[38] ENA/CSIRO, op. cit. page 83.

4.4 Potential constraints and risks

There are a number of potential constraints and risks in achieving the key principles for future market and regulatory design (outlined in Section 3.2) identified by KPMG. These constraints and risks are shown in Figure 6 and described in further detail below.

Figure 6. Constraints and risks – Procurement of NSS



4.4.1 Direct NSS procurement by DSO

The direct procurement of NSS from customers could create both risks and issues for all market participants. The materiality of these risks will vary over the different stages of market development and the level of DER deployment across individual networks. These risks and issues include, but are not limited to:

- There is potential for a DNSP to under-pay the DER owner the associated network value. This is a reflection of the DNSP being the single buyer of network support services and is complemented by the cost minimisation incentives under the economic regulatory framework. The current lack of transparency on the potential network value from DER adds to this risk (discussed in further detail below). By contrast, the competitive dynamic inherent in the energy market should drive up the value offered to customers.
- Where a DNSP and DER owner enter into a contract for NSS directly, this has the potential to create issues with regards to enforcement and compliance with respect to the terms of the contract entered into. This may require a means to financially penalise a DER owner if it fails to comply with the contract terms. To some extent, this is addressed in the current form of network support services (e.g. load control) by the DNSP having the direct means to control the technology. This potential issue supports a DNSP's desire for a firmness of response from DER in order to avoid this issue moving forward.
- Providing a DNSP with the direct means of control could prevent the DER from accessing other revenue from competitive DER-related products. In this context, retailers or other intermediaries might be able to resolve this issue through creating more products which better manage this risk.
- A key question for the market transformation is how to transition from the current DNSP owned load control assets to procurement from competitive providers. The AEMC metering contestability rule change attempts to provide a framework for encouraging this transition.
- Some consumers may not have the means and ability to fully understand and evaluate any offer from the DNSP for network support. Therefore, there is a risk that consumers do not make an informed choice when entering into a contract with a DSO for NSS. While this may be an issue to all forms of DER procurement, there may be additional confusion from a DNSP attempting to

procure directly from customers given that a customer primarily has a relationship with their retailer and not their distributor.

4.4.2 Lack of investment certainty

There could be a further issue of whether a DNSP can provide certainty of revenue flows to DER owners or intermediaries/aggregators to promote investment decisions. A DNSP procurement of DER may be tied to the five yearly regulatory control periods, and the need to seek AER approval to operational expenditure. This is further emphasised by the existing economic regulatory framework whereby the DNSPs are required to forecast, plan and manage the operation of their individual networks in accordance with defined service targets and reliability performance measures.

While a DNSP, and the existing economic regulatory framework, may not provide for investment certainty for a DER owner, this may not be a barrier to wider investment given the other drivers at play for consumers seeking to invest in such assets. For example, an investment in rooftop solar PV and/or battery storage are likely to be primarily driven by a desire on behalf of the consumer to better manage their energy usage, at a hopefully lower cost moving forward.

4.4.3 Delays to network tariff reform

As discussed in Section 6, reliance on procurement of NSS from DER could delay network tariff reform as it places less pressure on facilitating customers' response to resolve network limitations through tariffs.

4.4.4 Lack of market transparency in the value of NSS

The value of NSS varies both over time and across the distribution network for any given moment. For example, when constraints are emerging (whether in operational or planning timescales) on a particular distribution element, such as a zone sub-transformer, the value of NSS in the distribution zone served by that element will rise accordingly. Here, the alternatives to NSS in this instance may be network augmentation or load shedding, in the planning or operational timescale, respectively.

There are considerable elements on a distribution network and, of course, constraints depend upon both the capacity of the element and the amount of downstream load that it serves. A DNSP's role (as a DSO) is to keep track of these variables and take actions accordingly to maintain distribution system reliability and security. Thus, to the extent that it exists at all, information pertaining to NSS value is held by the DNSP.

On the other hand, retailers (and customers with DER) have no direct information on these matters. They are only aware of the location and loads of their customers. To assess the value of NSS, a retailer will rely almost entirely on information provided by the DNSP. As we see further penetration of DER in the network, and therefore a potential increase in the variability (and potentially uncertainty) of energy flows, understanding this value will become of increasing importance.

A retailer or other third party providers are likely to be at a substantial disadvantage to the DNSP in designing and preparing NSS products and capabilities. In addition, customers (or their agents) may have no means to properly assess the price offered by the DNSP for the DER service.

For example, NSS provision is likely only to be economic in zones where NSS value is high. Whilst a retailer could, in principle, prepare NSS offerings in all zones of the network and sell these to the DSO, this is extremely wasteful and costly. If the retailer knows in advance where the high value zones are, it can concentrate its efforts in those zones, ensuring the NSS to be delivered are consistent with the requirements of the distributor for the time period in which they are required. That is exactly what the DNSP will do, of course, in developing its own direct procurement NSS.

In this context, if there is any perception that the DNSP has a commercial interest to either favour its own in-house DER solutions, or capital expenditure, then there will be a concern that the DNSP is abusing these information asymmetries. Such concerns will exist even in the absence of any actual commercial incentives if stakeholders perceive that the DNSP has the ability to act in a biased manner.

We note that currently, DNSPs provide a considerable amount of useful information to the market regarding network limitations. This obligation has recently been extended under the AEMC final determination for Local Generation Network Credits Rule Change.[39] Going forward, under a high DER scenario, a DNSP may volunteer to provide additional information, on the basis that this will improve the value and suitability of products that retailers and other third parties develop and offer.

These information provision obligations, are unlikely to be sufficient by themselves to address this issue. Rather, there will be a need for increased regulation and monitoring of contracts, as well as DNSP behaviour in the procurement of DER for NSS, in order to address any mis-alignment between DNSP interests and market efficiency and to ensure that outcomes promote the interest of customers. Such additional regulation may be required to provide confidence to market participants and DER owners, for example in the following areas to test:

1. That the price paid for NSS is compensative of the value provided;
2. That DNSP procurement of NSS is efficient – that is, the DNSP has selected the most efficient option available;
3. That the assurances placed on the procured DER are appropriate and necessary from the market perspective;
4. When the DNSP has called on DER services, that the DNSP has utilised the DER in an efficient manner.

The operation of a market for network support, including the NOM as proposed under the Roadmap, may also need to be regulated to ensure that the DNSP arrangements for allowing parties to participate in the market is consistent with market efficiency as suggested by the assessment principles set out in Section 3.2 above. This framework should provide for open access to all potential participants and technologies, ensuring competitive and efficient market outcomes.

Further, in order to provide sufficient market transparency, a DNSP could be required to regularly report on market outcomes. Depending on the granularity of reporting, such transparency may provide necessary operational and price signals to investors seeking to install DER and for other parties to develop DER products. Therefore while a market for network support might address some of these risks through providing more transparency and confidence to market participants, it is still likely to require additional regulation. Such regulation requirements will create costs for both the regulator and DNSPs.

In addition, regulation creates its own risk and could have unintended consequences. As it is generally better to promote efficient outcomes through competitive markets rather than regulation, there may be a need to consider alternative incentives to encourage procurement via third parties where that is viable, as a better alternative than trying to regulate outcomes under DNSP procurement models, such as the NOM.

[39] The final rule requires DNSPs to publish a 'system limitation report' in accordance with a template prepared by the AER. The system limitation report will be published annually in conjunction with each DNSP's annual planning report. By providing key information about system limitations in a consistent and accessible manner, the report seeks to allow providers of non-network solutions to focus on locations where their solutions could be used to defer or avoid investment in the network.

4.4.5 DNSP future choice: in-source or out-source NSS

The direct procurement of NSS from a DER owner is not a reflection of an owner's efforts in developing new NSS products and pitching these to DNSPs. Rather, DNSPs are developing the (regulated) products themselves and then offering to buy such products from consumers. In contrast, retailers/aggregators will develop their own products and will pitch these products to DNSPs.

There is only one DNSP buyer but many potential sellers. Ideally, a DNSP can and should buy the best product, irrespective of its source. However in practice, where the monopsony buyer is also a product developer, it would be asking a lot of human nature and business culture that the buyer would be unbiased when choosing between its own products and the products of another. Indeed, psychology aside, given the sunk costs involved in product development, it would be entirely rational for the buyer to choose its own products, and aim to recover some of its sunk costs, rather than buy an offering from another party.

A DNSP's experience may incline it to look more favourably on the products it has developed (and less favourably on products developed within the competitive market, such as those developed by retailers or other third parties), because its own products embody its own understanding and preferences. A DNSP will have a greater understanding of what its own products can offer and the associated risks. In this respect, the fact that the DNSP designed the products itself is not strictly relevant; it would look equally favourable on an identical product developed by a third party. However, without the same understanding as a DNSP, it is unlikely that a retailer would, in fact, develop such a product.

Even if the DNSP can behave in a way that overcomes any internal bias, there will always be a perception by market participants that such a bias exists given this interaction between buyer and product developer. This perception may be a precursor to greater regulation, as discussed above.

4.5 Advice and future work

4.5.1 Advice

DER has the potential to deliver substantial efficiencies and savings to distribution networks. Modelling conducted for the Roadmap estimated that network tariffs could be 30% lower by 2050 compared to today through DNSP use of DER.[40] The framework for how DNSPs procure DER resources for network support services will have a material impact on the efficiency and development of DER markets, products and services.

Our assessment has identified some risks under a DNSP procurement model, notably around the issue of DNSPs procuring directly from customers. As a monopsony buyer of NSS, consideration must be given to the risks resulting from a DNSP's potentially advantageous position including ensuring DER owners / third parties are insufficiently informed or prepared to enter into such negotiations or contractual arrangements. The risks identified above could result in the following outcomes:

- DER owners not being appropriately compensated for the network value derived from the DER;
- Lack of transparency on how a DNSP values and procures DER for network support; and
- Onerous control provisions being placed on DER preventing it from accessing other sources of resources or even delivering value to the market during wholesale price stress events.

[40] Energeia report to ENA/CSIRO – Unlocking Value for Customers – enabling new services, better incentives, fairer rewards.

A DNSP should be encouraged to utilise the most efficient source of DER, regardless of whether that DER is sourced directly from customers or via a third party retailer or aggregator. The DNSP should be indifferent to whether NSS products are offered by retailers or aggregators, except to the extent that the price or quality of the product is different, or perceived to be different. There is currently a debate under a number of rule change proposals regarding whether the current incentive arrangements supported by information disclosure are sufficient to achieve this outcome.

In our opinion, under a high DER scenario, there will be a greater need for regulation of DNSP procurement of DER. This would be needed to address any potential bias or discrimination by DNSPs and to provide confidence to the market. The impact of a perception of bias on market confidence should not be under-estimated. Regulation would need to be adequate and robust in the following areas:

1 Customer protection for DER owners;

2 Information provision to the market on DNSPs' needs and capability;

3 Assessment of DNSP expenditure requested for both DER-related services and for enabling technology; and

4 Monitoring of outcomes under DNSP involvement in DER.

However, such regulation will have costs and additional risks. The additional complexity in the nature of DER and its utilisation will add to the burden on the regulator to design the arrangements correctly to best promote market efficiency.

The need for regulation would be greater if the primary means through which DNSPs are procuring DER is directly through customers, given that the information asymmetries and potential for pricing discrimination may be higher. Similarly, such regulation may be necessary where DER owners or third party providers are prevented from sharing in the associated network benefits derived from DER.

While recognising this, DNSPs should continue to have the ability to procure directly from customers, especially in the short term. Not doing so would prevent consumers from accessing potential sources of value associated with their investment. Further, such procurement will directly support the development of DER technologies over the longer term. For existing arrangements such as hot water tariffs, it would not be in the customer interests for such services to be prohibited immediately. What is important is that any legacy arrangements are appropriately managed through the transition to competitive DER markets so that they do not preclude co-optimisation.

4.5.2 Future work

Key areas for future work include:

- Development of a transparent and credible methodology on how the DNSP calculates the prices for DER services;
- Establishment of clear and effective operational procedures and boundaries in relation to how a DNSP may use DER (this includes a framework for governing how a DNSP would be allowed to curtail DER when necessary to maintain network security); and
- Consideration of how to provide effective and clear information to consumers regarding their DER capability and how to maximise value from their investment.

5 Co-optimisation between markets

A situation of high penetration of DER across networks could foster the emergence of multiple commercial trading platforms for DER-related products and services. It is difficult to predict the form and design of such commercial platforms given the uncertainties regarding the future capabilities and costs of individual technologies and the supporting frameworks established by the sector. It is likely to be the case that multiple variations of such platforms, across different locations and the markets will evolve over time.

This section explores the questions relating to how the functions and behaviours of DNSPs could impact on achieving co-optimisation between markets established by DNSPs for NSS and other commercial platforms for DER services.

Key findings

1. Under a high DER scenario, there could be a need to coordinate the deployment of DER across multiple markets. In delivering NSS, a DER will generate, or consume, energy at times that are of most value to the distribution network. In delivering energy, on the other hand, the DER will operate based on the value to the wholesale energy market and other market participants. While these times might coincide, often they will not. Therefore, co-optimisation will be important for promoting the efficiency of DER through allowing customers to capture the full value of their DER asset.

2. A market for procurement of NSS from DERs established by a DNSP creates questions as to how this market should interact with other commercial platforms for DER services, as well as whether any such establishment will impact on the commercial viability of such platforms.

3. Markets that co-optimise by design should be more efficient and hence attract participants. Therefore, regulation may be unnecessary, although this depends upon other factors such as free-riding, transaction costs, and coordination costs. If a commercial platform is effective at marketing and co-optimising the multiple DER-provided services, this should lower the price of NSS and encourage the DNSP to use it.

4. However for a DNSP to use commercial platforms for the procurement of NSS, a degree of trust will be required in the ability of such platforms to deliver, especially in the early stages of development. DNSPs are likely to have an understandable preference for their own products and solutions. In addition, there could be a considerable "first mover" advantage to establish a market for network support before any commercial platforms emerge.

5. It is important for the framework going forward not to create any preference or incentives for the DNSP to favour its own market platform over other platforms. There is a need to ensure that a DNSP established market is open and transparent, to facilitate co-optimisation between NSS and energy service delivery. Also DNSP policies and operations will need to be assessed and monitored to ensure they do not favour one market over another.

6. The co-optimisation of a market for network support with other markets needs to be fully considered at the design stage and evaluated under any regulatory approval of investment. Trying to retro-fit the appropriate arrangements at a later date may be too difficult and may create uncertainty for the market.

5.1 ENA/CSIRO Roadmap

The ENA/CSIRO Roadmap has identified the need for changes to the design and operational practices across the entire electricity system to support a transition to an electricity sector with zero net carbon emissions by 2050.

In relation to the co-optimisation of the system, the Roadmap provides for an initial approach to be established by 2019, coordinating and optimising the decisions of the independent market operator and distribution connection points in real time and using automated signals. A key component of this approach will be access to the information at the interface between the transmission and distribution network. The ENA/CSIRO note this will need to be supported by *"enhanced hierarchical control strategies embedded within the distribution system to assist in meeting information and control functionality requirements at the interface."*[41]

In describing the development of a NOM, and specifically a more sophisticated dNOM, the ENA/CSIRO have identified the potential for a dNOM to "support a range of other innovations." This may be interpreted as alternative platforms or markets – such as a DEM – however the ENA/CSIRO, while recognising the intrinsic relationships between a potential DEM and NSS, has chosen not to presume what design a future distribution-level energy market may take, or what platforms may be utilised to facilitate such markets.

While the Roadmap does not explicitly discuss the optimisation of multiple DER-related markets, and does not reference how alternative platforms relating to these markets may be coordinated, it is proposed a multi-application platform be developed enabling the application of a common set of network, security and integration services. The ENA/CSIRO consider this approach will provide independence without restricting resources to any one particular hardware platform.

On 27 March, the ENA/CSIRO released a further Synthesis Report into the issues relating to market platforms and lessons from overseas jurisdictions.[42] Drawing from research conducted by international consultants, this report further develops the Roadmap thinking on network operations and market optimisation under greater DER penetration. The report states that the development of a NOM is a critical development to allow network businesses to unlock the potential for DER services to optimise network operations and reduce network costs in Australia. The report also notes that the form of the NOM must evolve to increasing levels of sophistication and scope as experience is gained and the approach is proven.

The Synthesis Report advises that a range of market design features must be applied to ensure that customers, networks and society benefit from distributed energy resources orchestration. Regarding this, the report recognises that a critical issue in Australia is developing the capability to ensure management of the interface between the wholesale electricity market operator and the distribution network systems given the increased complexity and uncertainty under a high DER scenario.

[41] Energy Networks Australia and Commonwealth Scientific and Industrial Research Organisation. Electricity Network Transformation Roadmap Final Report. April 2017.
[42] Electricity Network Transformation Roadmap – Future Market Platforms and Network Optimisation Synthesis Report, 27 March 2017. Due to timing, we have not had the opportunity to properly consider this report in our assessment.

5.2 Key principles for future market and regulatory design

As per our assessment criteria (described in Section 3), KPMG considers the following market design and regulatory principles in relation to co-optimisation between multiple markets to be necessary in order to achieve market competitiveness and efficiency for DER-related products and services:

- The ultimate decision on how DER is utilised across buyers is with the owner of DER;
- Any potential conflict between market operators[43] (MO) and the DSO are transparently managed (e.g. through information exchange);
- Clear separation of responsibilities between MOs and DSO; and
- Orchestration of DER services across multiple markets is achieved in a manner consistent with efficient outcomes.

5.3 Potential constraints and risks

Having a high volume of DER transacting on multiple commercial platforms would significantly alter network flows, the nature and role of distribution networks and how DER owners seek to maximise the value of their assets moving forward.[44]

The development of multiple commercial trading platforms for DER will result in greater complexity in how DER-related products and services are utilised and managed in the market more broadly, depending on:

- The type and level of sophistication of platforms established,
- The products or services traded; and
- The ability for participants to access or participate in specific markets.

These markets will have implications for not only how DNSPs manage their network but also how DER owners maximise the value associated with their assets. In addition, the existence of multiple markets will present a number of constraints and risks through co-optimisation of the markets to protect the competitiveness and efficiency of any one market.

We have discussed these constraints and risks from four perspectives, as shown in Figure 7.

[43] By market operators, we mean any party responsible for managing and clearing transactions related to energy and/or DER services. This covers AEMO as the market operator for the wholesale market, the DNSP nominated entity for the NOM in addition to any market operator for a commercial DER platform. As there could be multiple platforms, there could be numerous market operators in the future.

[44] Network flows are a function of DER deployment and output rather than the platforms on which they trade. DERs could respond autonomously to existing market prices (wholesale spot price and network tariffs) with no new platforms. However, the emergence of platforms could lead to DER owners responding more often and changes in behaviour.

Figure 7. Co-optimisation – constraints and risks

Co-optimsation between NSS and energy provision	Procurement of NSS via commercial platforms	Optimisation across network operation and market operation platforms	Emergence of commercial peer-to-peer energy platforms

5.3.1 Co-optimisation between NSS and energy provision

A critical feature of DERs are their potential ability to deliver both NSS and energy to the network (i.e. multiple use application).[45] For example, a single installation of energy storage has the potential to provide multiple services to several entities with compensation provided through different revenue streams. The emergence of commercial platforms will create more opportunities for DER resources to tap into different revenue streams.

The ability to "stack" the incremental values a DER may provide across these multiple uses – i.e., the wholesale market, distribution networks, retailers and customers – it may be necessary to make DER economically viable.

This report has identified a range of potential regulatory or market barriers limiting the ability of DER resources to capture all the value across multiple revenue streams. This section looks at how the use of DER for NSS by DNSPs could potentially impact how the value of DER is optimised across these multiple uses.

In delivering NSS, a DER will generate, or consume, energy at times that are of most value to the distribution network. In delivering energy, on the other hand, the DER will operate based on the value to the energy market (and the buyer of the DER service) in which it is selling its output at a given point in time. While these times might coincide, often they will not. For example, high wholesale energy prices may coincide at times when there are export constraints in the distribution network. A DER would need to increase output to deliver energy but decrease output to deliver NSS.

As NSS and energy delivery may conflict, the owner of a DER will be required to choose between the two. A rational owner will choose to deliver to the market that provides the higher value. This choice – or series of decisions – is a "co-optimisation" of service delivery across the two markets.

Co-optimisation decisions can take place in different timescales. In the example above, the DER owner has to make a "spot" decision about whether to increase or decrease output from the DER. However, the decision may have already been made in an earlier transaction. For example, the DER owner may have contracted the control of its DER to a DNSP, in which case the DER will deliver NSS rather than energy, for the period of the contract (at least, when the DNSP decides to operate and control the contracted DER).

Where NSS is provided by a retailer, who also supplies the consumer with energy, the retailer will be able and incentivised to control the DER in order to co-optimise NSS and energy. However, in the case of direct procurement where the DNSP controls the DER in order to receive NSS, the DNSP is not able or incentivised to co-optimise as it is not able under current rules to be an energy retailer and sell into the wholesale market.

In fact, in this case, the consumer finds itself in the position of deciding how to achieve co-optimisation between the DNSP and other potential buyers of the DER services. In a situation where the DNSP

[45] A DER may deliver other services which a distributor or party may choose to purchase such as frequency control ancillary services ("FCAS"). For simplicity, KPMG has confined its assessment to NSS and energy services only.

controls the DER to procure NSS, the consumer is the only party in a position to decide how to potentially co-optimise service delivery with other buyers. Given the complexity of the co-optimisation problem, few consumers would be able to undertake this task effectively and are likely to default to only contracting with the DNSP for the procurement of NSS.

Direct procurement by DNSPs therefore places the onus of the issue of co-optimisation onto the consumer, while indirect procurement transfers this issue to a third party (i.e., a retailer or aggregator). The latter is likely to be able to undertake this much more effectively, leading to higher value from DER operation and a long-term benefit to the consumer. This is likely to work better in a dynamic market situation where prices can be more flexible and vary in real time. The third party is able to make informed choices in this context whilst consumers, generally, cannot.

In all cases, a well-functioning market for NSS will depend on the capabilities of technologies connected to the area of the distribution network subject to the DNSP platform. This means that any DER procured by the DNSP will be required to be maintained so that the necessary state of response (i.e. battery charge or discharge) can be achieved when necessary to provide the service compensated through the DNSP regulated revenue.

In this situation, the ability of the DER to access other revenue streams will depend on:

- Whether the priority for which the DNSP will require the DER resource is reasonably predictable as to size and the time it will arise on a given day of the year. If so, the DER resource should be permitted to deviate at other times of the day in order to provide other, market-based rate services;
- The terms and conditions under the DNSP procurement of the DER resource for network support services, including the penalty rates for non-compliance;
- The framework for how the DNSP can recover the costs through regulated revenues; and
- Obligations on the DNSP for maintaining a reliable, safe and secure network and how those obligations are translated into access and connection arrangements for DER.

It is possible DERs (with the appropriate technology) could switch between the provision of multiple services almost instantaneously. An electric storage resource receiving regulated revenues for providing one service may also be technically capable of providing other market-based rate services. However, in situations where the DNSP need for such resources is not reasonably predictable as to size or the time, the regulated NSS service may be the only service that the DER resource could provide.

Consideration should also be given to a distributor's position to prevent the development of other contestable markets for DER products and services. For example, where a DER is contracted and controlled by a distributor, this may prevent it from participating in other markets for DER products and services – leading to lower liquidity in that market. This will be subject to the contractual arrangements entered into by a distributor and DER owner. Presumably where a DER owner could make more money (and is fully informed of those opportunities) from these other contestable markets than from a distributor, it would switch to those markets. However, a potentially better outcome would result from the DER owner being allowed under the contract with the DNSP to participate in multiple markets, capturing multiple revenue streams, and thereby providing the opportunity to maximise the value of its DER.

Additionally, the multiple use of DER resources could lead to the perception of double recovery of costs by the DER through both regulated revenue and market prices. The regulator may consider that there is a risk that the price for NSS paid for by the DNSP, and which is then recovered through regulated revenue, may result in the DER resource being over-compensated given the possibility that the DER resource is also being compensated through other markets. The regulator could argue that the DNSP allowed revenue for NSS procurement should be net of any other payments received by the DER resource from other sources.

Any perception of double recovery could lead to increased scrutiny of the contract prices paid by the DNSP for NSS. A DNSP[46] may be forced by the regulator to seek to capture some of the market revenue from the DER resources and pass through this revenue to consumers.

Finally, if a DER participates in both an energy and NSS market, a DNSP may need some degree of assurance that the DER will deliver the NSS as agreed.[47] The framework should ensure that the DNSP does not go beyond an appropriate level of control or assurance. For example, the DNSP may further restrict suppliers to the NSS market from operating in the energy market or it might place obligations on the DER as a condition of connection. This will depend on how the DNSP assesses risk and uncertainty associated with the level of contractual control that the DER customer agrees to in the NSS contract. This matter would become more complicated if DER resources can also access revenue directly from the wholesale market (i.e. through aggregation), as allowed under the current NER.

We advise that further work is needed on how to co-optimise wholesale market dispatch of DER resources and network dispatch for network support services of the same resources

5.3.2 Procurement of NSS via commercial platforms

It is important for the frameworks going forward not to create any preference or incentives for the DNSP to favour its own market platform over other platforms. If a commercial platform is effective at marketing and co-optimising the multiple DER-provided services, this should lower the price of NSS and encourage its use by the DNSP.

A potential risk may manifest whereby once a DNSP establishes its own market platform it will become reluctant to procure DER from other commercial platforms. This may especially be the case if the DNSP's recovery of costs associated with the platform is dependent on its usage and outcomes. Therefore, if the platform is established first then this could influence the development of commercial platforms of DER services as it would create a disincentive for a DNSP to procure NSS via commercial platforms.

For a DNSP to use commercial platforms for the procurement of NSS, it will require a degree of trust in the ability of such platforms to deliver, especially in the early stages of development. Collaboration and joint trials would help to foster such trust. However, DNSPs are likely to have an understandable preference for their own products and solutions. This will cause the following issues for the efficiency of the market:

- Commercial platforms and DNSP platforms will likely develop independently of each other at the start which will lead to greater problems relating to co-optimisation issues in the long term.
- The establishment of DNSP platforms and the preference for them to use their own platform may impact on the commercial viability of other platforms.

Against this context, it may be very difficult for the AER to fully assess DNSP expenditure proposals to fund investment in a market platform (such as a NOM or dNOM) given such uncertainties regarding commercial platforms and the potential anti-competitive impact. The question to be resolved is whether the rationale for a regulated platform (regulated in the sense that it is being paid for through regulated revenue) is sufficient to address any anti-competitive impacts or whether such impacts could be resolved through the regulatory frameworks.

[46] Generators in the wholesale market could consider that the potential for cost recovery through DNSP regulated revenue will inappropriately suppress competitive prices in the wholesale markets to the detriment of other competitors who do not receive such regulated rate recovery.
[47] Market operators or buyers of products through the DEM may also need some level of certainty with regards to products purchased, particularly where there are multiple bidders and a need to settle a market.

5.3.3 Optimisation across network operation and market operation platforms

Traditional distribution system operation and planning may not be adequate under a high DER scenario, and in particular one where multiple platforms have been established. Multi-directional energy flows, varied resource types and shifting customer behaviour patterns on distribution networks in response to various price or operational signals could create new challenges for DNSPs.

The policy framework for considering how DNSPs should evolve in order to manage such transformation and challenges should not be undertaken in isolation from the interactions with commercial platforms, including that of the wholesale energy market. Specifically, through third party aggregators, it is possible that there will be DER involvement in the wholesale energy markets moving forward. This will influence the extent to which the AEMO (as the transmission system operator) needs to be involved in dispatch and operation of such commercial platforms.

Co-optimisation can either be undertaken by market participants or as part of market design. For example, the National Electricity Market (NEM) spot market co-optimises transmission, energy and FCAS markets. Ideally, the more efficient market designs should attract participants, without regulation being necessary – as long as any potential free riding by participants in costs can be avoided.

In order to effectively operate its network, the DNSP may need to understand and forecast any material impacts on flows resulting from other commercial transactions and uses of DER (e.g. non-NSS services). It is crucial to recognise this interaction because the DNSP should only need to procure DER resources for NSS when customer demand and behaviour on the network is leading to either a) a long term need to augment or replace the network or b) a short term need to maintain system operations.

There is clearly a material risk of inefficient procurement of DER resources by the DNSP if this is done independent of the market operations on any future commercial platforms established. Therefore, a need arises in light of the establishment of such platforms, to consider co-optimisation of the NSS procurement in conjunction with the operation of commercial platforms. There are various options to consider, depending on where the responsibility rests. There will be an increasing need to co-ordinate – and perhaps eventually integrate – energy markets with the NSS market or vice versa.

In the future, effective and real time communications between platforms may be required. Issues regarding funding and cost recovery of such infrastructure is uncertain may be further complicated by by allocation issues across a DNSP markets for network support (which could be considered to be regulated as it will be funded from regulated revenue) and commercial platforms.

The collection and sharing of data will be a key aspect of any framework design. The physical coordination of DER schedules and dispatch by market operators and DER providers needs to be known by the distribution system operators to ensure that it can be accommodated over the distribution network. Similarly, retailers will need to know when distribution businesses call on DER services and control output at DER sites as this impacts on their hedging positions and liabilities to the wholesale markets. Therefore, rather than debating which party has the greater priority to the information, stakeholders should come together and develop a common framework which recognises all interests and information needs.

5.3.4 Emergence of commercial peer-to-peer energy platforms

The nature and design of commercial peer-to-peer energy platforms for DER services will vary and pass through multiple stages of design with increasing levels of sophistication and scope as experience is gained and the approach is proven. These platforms may be simplistic in their infancy, for example matching consumers and providing for peer-to-peer trading in electricity only. In the beginning, this would effectively represent a netting transaction, where one customer load increases while another customer load on the network decreases commensurate with the DER technology in question.

Such market activity may not have an immediate impact on a DNSP's functions. Co-optimisation between a DSO and market (or platform) operator may therefore not be crucial at the start and may not be needed for certain markets at all. However, where the volume of activity is sufficiently large and a threshold is reached, a DNSP may seek to have control or the ability to influence the operation of the platform, which in turn creates policy questions regarding how such control could be exercised, if any, and whether the market is sufficiently large and diverse to ensure competitive outcomes. Having a prior understanding of the threshold point where peer-to-peer transactions would materially affect the safe and reliable network operation, and the factors contributing to that point, will be important.[48]

Further in the future, effective control by a DNSP may not be warranted where real time communications between platforms is established, providing both the market operator and DSO sufficient information in order to facilitate a competitive market place and manage the network efficiently, respectively.

We are currently seeing the emergence of various peer-to-peer models being developed in Europe (see Box 2 below), Australia and the United States. The current commercial models facilitating peer-to-peer trading proposed or on trial are primarily looking at ways to by-pass traditional retailers (and their supply costs) and to match customer preferences to be solely supplied from either renewable sources and/or energy sources which are known to the customer. Further, these platforms have not required changes to a DNSP's functions. Issues in their development have been primarily related to metering, settlement procedures and the payment of full network charges.

Box 2: Peer-to-peer platform examples.

Open Utility, a UK start-up energy technology company has developed 'Piclo', the UK's first online peer-to-peer trading service for renewable electricity. The aim for Piclo is to provide an 'eBay for energy' where renewable generators will be able to sell their electricity directly to their neighbours, local businesses or schools for the best price. The scheme aims to give energy consumers more transparency and control over renewable energy purchases than in the past. It is backed by the UK Government's Department for Energy and Climate Change (DECC) through its Energy Entrepreneurs Fund scheme alongside digital social enterprise funding.

Under this service, the customer will use a web interface to select a merit order of generators and prices to buy electricity from (this may be local generators or a certain technology). The Piclo software matches every half hour of demand with the requested generation merit order. Therefore, a pre-condition for participation is that the customer has half-hourly billing. One of the objectives of peer-to-peer transactions is to avoid retailer supply costs by dealing directly with generators. However, a licenced retailer is required for settlement and billing purposes. Open Utility has partnered with a renewable electricity supplier, Good Energy. The generator will also have a Power Purchase Agreement with Good Energy (managed by Open Utility). It is expected that a generator will seek to sell its own brand and offer discounts for particular customers.

Greensync deX Recently, ARENA decided to fund GreenSync to carry out a decentralised energy exchange project. GreenSync, deX brings together the expertise of two network operators (United Energy and ActewAGL), two leading energy startups (GreenSync and Reposit Power), a new energy retailer (Mojo Power), as well as ARENA. This will involve establishing a software based marketplace that will, for the first time, allow households and businesses to trade the grid services provided by their batteries and rooftop solar with their local network operators. This trial will assist in informing on the design of platform models and potential regulatory issues in Australia.

[48] In theory, such a threshold point may never occur if there is substantial spare capacity on the network or if the peer-to-peer transactions do not materially change the current network flows.

5.4 Advice and future work

5.4.1 Advice

We note that the nature and design of commercial platforms will vary and likely go through multiple stages of design with increasing levels of sophistication and scope as experience is gained and the approach is proven. In design of these platforms, it is vital that each market provides for open and transparent participation in order to facilitate co-optimisation of market outcomes. This is of particular importance where an individual DER participates in multiple markets (a reflection of the incremental revenue which may be earned from the asset), for example, where a DER is capable of providing both NSS to a DNSP and delivery of energy services to a peer or other third party.

Furthermore, as these platforms mature and become more sophisticated in both the products and services traded as well as their technology solution, and as we see wider uptake of DER technologies by consumers, effective and real time communications between network and market operators of individual platforms may be required. This will ensure not only efficient market outcomes, but also that appropriate price signals are provided to investors seeking to invest in new DER.

Such communication technology will come at a cost. Payment (and cost recovery) for such infrastructure across regulated markets and commercial markets will require further consideration. The issues regarding funding models and cost recovery of such infrastructure remains uncertain under the current NER.

Markets that co-optimise by design should be more efficient and hence attract participants. Therefore, regulation may be unnecessary, although this depends upon other factors such as, but not limited to, free-riding, transaction costs and coordination costs.

If a commercial platform is effective at marketing and co-optimising the multiple DER-provided services, this should lower the price of NSS and encourage the DNSP to use it. However for a DNSP to use commercial platforms for the procurement of NSS, a degree of trust will be required in the ability of such platforms to deliver, especially in the early stages of development. DNSPs are likely to have an understandable preference for their own products and solutions. In addition, there could be a considerable first mover advantage to establish a market for DER related products or services before any commercial platforms emerge.

It is important for the framework going forward not to create any preference or incentives for the DNSP to favour its own market platform over other platforms. There is a need to ensure that the market is open and transparent, to facilitate co-optimisation between NSS and energy service delivery. Also DNSP policies and operations will need to be assessed and monitor to ensure they do not favour one market over another.

This stresses the general point raised in this report regarding the need for regulation to ensure that it is an open and transparent market and is able to facilitate co-optimisation between NSS and other DER services.[49]

[49] It is therefore unclear if increased DER penetration will require new network infrastructure, including for example protection systems, to support its operation. Customer behaviour may become simple to forecast due to use of IT controls and the broader roll out of advanced metering infrastructure. This uncertainty about how the market will evolve makes it difficult for a regulator to approve new infrastructure proposed by a DNSP, and can create a material risk for customers as they could be required to pay for infrastructure they do not need or (importantly) may not have been given the opportunity to change their behaviour to avoid the need for the protection systems (i.e. through network tariffs).

There is a potential risk that co-optimisation will not be properly considered at the start of a market, particularly where multiple markets are established targeting specific technologies, participants or even individual networks, and therefore will become an issue for attempting to retro-fit solutions for co-optimisation.

However, this should not necessarily regard governments to intervene in the development of commercial platforms. Markets and private investment are better equipped to solve these issues and regulatory intervention in the early stages may stifle innovation. Instead what is important is to ensure that the design of a market for network support does not act as a constraint to commercial platforms and co-optimisation. Therefore the issue of co-optimisation of needs to be fully considered at the design stage and evaluated under any regulatory approval of the required investment. Trying to retro-fit the appropriate arrangements at a later date may be too difficult and creates uncertainty for the market.

5.4.2 Future work

Key areas for future work include:

- Development of the regulatory and market arrangements to facilitate peer-to-peer transactions. This is likely to require considering how the costs across the electricity supply chain, including government scheme costs, are levied on such transactions in additional to issues relating to customer protection and settlement. For example, whether such transactions should be exempt from paying transmission charges or retailer obligations (renewable energy or energy efficiency certificates, for example).
- Establishing a framework for collecting and sharing data across market participants. It will be essential for networks to have visibility of the physical operation of DER participating in the wholesale market and other commercial platforms. Similarly, retailers will need to know that when distribution businesses call on DER services and control output at DER sites, this impacts on their hedging positions and liabilities to the wholesale markets. The industry should come together and develop a common framework for information sharing which recognises all interests and information needs.
- Establishing clear and effective operational procedures and boundaries in relation to how a DNSP may use DER (this includes a framework for governing how a DNSP would be allowed to curtail DER when necessary to maintain network security).

6 Network tariffs

Network tariffs could play a significant role in unlocking the value associated with DER and the current change towards greater cost reflectivity in network tariffs would help to better reflect and reward the network value from DER to consumers. This section tests the current network tariff arrangements and those proposed under Roadmap against our assessment framework.

Key findings

The design of network tariffs which will best promote the development of DER – locational, coincident demand charges – are unlikely to be implemented given current political concerns. However, this does not mean that tariff reform will not be important for DER development, and tariff reform still needs to be conducted in the way which delivers the most efficient outcomes. Regarding tariff reform, we found:

1. DNSP proposed demand tariffs are not totally reflective of network value as they are based on non-coincident peak and are not locationally specific. Since it is coincident demand that drives network augmentation costs, such tariffs are only cost-reflective to the extent that the coincident and non-coincident maximum demands happen to occur at the same time. For residential customers, this is the exception rather than the rule.
2. Customers with low usage will - at some point - find it worthwhile disconnecting from the grid and, increasingly, the grid will be de-populated as the residual charge increases. The Roadmap recognises this risk from fixed charges, and proposes a discounted tariff for those liable to disconnect from the grid. This is an important start, but further analysis is required as to how best to structure residual charges to all customers.
3. Constraints with current Rules could prevent different network tariff designs from being considered (for example, prohibition on export tariffs under NER clause 6.1.4).
4. To date, there has been a lack of consideration regarding the appropriate tariff structures for DER transactions. For example, there is a need to consider the cost reflective tariff for peer-to-peer transactions and whether such transactions should be relieved of the requirement to contribute to transmission network costs.
5. The prospect of asset stranding could discourage DNSPs from tariff reform. The materiality of this issue may increase under an environment of high DER penetration.
6. The five year lag between tariff structure statements creates a material risk that tariff reforms fail to keep pace with market developments.

The challenges with achieving tariff reform mean that other mechanisms for DNSPs to reward and assist DER will continue to play an important role going forward. These mechanisms are discussed in other sections. However, there is a risk that DNSPs may, over time, become less encouraged to design tariffs to correctly address network peak demand growth, if they believe they can manage this through NSS procured with consumers or through capital investment.

6.1 Current arrangements

The penetration of DER in recent years has placed greater emphasis on the development of cost reflective network tariffs in order to promote, among other factors, greater efficiency (through the provision of more information in relation to the network) in the decisions of distributors investing in the network and consumers investing in DER. For example, such efficiency may be identified whereby cheaper DER investment leads to avoided network costs for a given location.

Recognising this, in November 2014, the AEMC handed down its final rule determination titled "Distribution Network Pricing Arrangements." The rule determination provided for *"new rules that will require distribution network businesses to develop prices that better reflect the costs of providing services to individual consumers so that they can make more informed decisions about how they use electricity."* [50] This rule change was part of a broader package arising from the AEMC's Power of Choice review encouraging greater consumer participation in the energy market.

As part of the final rule determination, DNSPs are required to develop network tariffs that are cost reflective, providing for efficient pricing signals to consumers. Tariffs must comply with new pricing principles such that they:

- Are based on the long run marginal cost of supply;
- Reflect the business' total efficient cost of providing services to a consumer assigned that tariff;
- Give effect to the consumer impact associated with changes in tariffs and consumers' ability to understand those tariffs;
- Comply with jurisdictional requirements; and
- Avoid cross-subsidies between consumer groups.

Further tariffs are to be developed in a two stage process:

- **Stage 1:** Development, consultation and approval of a Tariff Structure Statement (TSS) providing for price structures and indicative price levels to be submitted to the AER at the same time as a distributor's revenue proposal; and
- **Stage 2:** Development of annual price levels, to be approved by the AER, consistent with the TSS, pricing principles and other rule requirements.

A key element in this process is a requirement for distributors to demonstrate how they have taken stakeholder views into account in their TSS. The final rule does not prescribe one method of consultation to be adopted by a distributor, rather, it provides distributors with sufficient flexibility in their approach and intent.

A TSS may be amended within a regulatory control period subject to the AER's testing and approval where events that are deemed outside of a distributor's control, could not be reasonably foreseen and are likely to result in a materially better TSS. The AEMC has indicated that these events may include (subject to tests of the TSS) smart meters, changes in demand conditions, deployment of new technologies (including DER) and changes in jurisdictional obligations.

Cost reflective network tariffs based on the long run marginal cost (LRMC) are intended to signal the costs incurred by DNSPs in investing in their network to meet future demand. Tariffs therefore are intended to reflect the costs of increasing capacity at different locations across the network, and they

[50] Australian Energy Market Commission. National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014. 27 November 2014.

should therefore reflect the network value caused by DER reducing the need to build additional capacity. Hence, if customers are faced with a LRMC network tariff, the decision to install a DER will be rewarded through lower network tariffs. The size of that reward will be equal to the avoided capacity investment benefit caused by DER.

The NER do not prescribe a particular method for estimating and calculating LRMC. LRMC may be defined as the long-run cost of supplying a sustained, unit increase in demand. In the distribution context, LRMC is typically considered to reflect three factors:

- The unit cost of distribution provision – for example the $/kW cost of network capacity[51];
- The current level of spare network capacity – in other words, the difference between installed capacity and coincident peak demand; and
- The rate of growth in peak demand.

These three factors arise because there is perceived to be no requirement for – or cost of – network expansion until current network capacity is exhausted. The time at which this occurs is the current spare capacity divided by the rate of growth.

Under the NER, distributors have some flexibility to decide how best to implement and apply LRMC. This has resulted in differences in the methodology employed. For example, in their TSS, most Victorian DNSPs have used a 10 year planning horizon, while Jemena used a 20 year period.

6.2 ENA/CSIRO Roadmap

Network tariffs are set to play a significant role in unlocking the value associated with DER. This has been identified by the ENA/CSIRO as a key driver of change towards incentivising efficiency and innovation in the market and specifically in the adoption and integration of DER and the products and services which may be made available from these assets.

To facilitate this, the Roadmap provides for an accelerated transition of customers towards more cost reflective tariffs and implementation of new pricing options (recognising the difference between those with DER and those without). This is to be supported via rapid uptake of smart meters in the short term across all states (excluding Victoria, which has already rolled out smart meters).

Specifically, the Roadmap provides for amending network tariffs with residential and small business customers assigned to new (opt-out) demand based tariffs by 2021. From 2021, a second wave of tariff reform will emerge with a range of new tariffs to be introduced differentiating between services whereby certain customers may be self-sufficient at certain times and/or others who may wish to trade on non-traditional platforms. Finally, by the end of the assessment period (2027), these amendments to tariffs will lead to the dynamic and locational based use of DER and specifically the selling of services by customers directly to networks or through their agents. The four milestones are set out below.

Table 5. ENA/CSIRO Roadmap pricing and incentive milestones

Foundation Phase (2017-2022)
Milestone 1: By 2021, there will be early transition to better tariffs where residential and small business customers are assigned to a new range of demand based electricity tariffs, enabled by a high penetration of smart meters. These tariffs take into account future uptake of new technology and are offered to customers through a range of retail price offerings and structures with the right to opt-out, effective customer support and decision making tools, and reforms to government concession schemes.

[51] This example may change over time in an environment with high DER penetration.

Foundation Phase (2017-2022)
Milestone 2: From 2021, new prices will be introduced to reflect new and differentiated services desired by customers, including self-sufficient supply of energy at some times, and the ability to trade energy on non-traditional platforms (peer-to-peer arrangements).   **Milestone 3:** From 2021, micro-grids and standalone power systems will be a feasible alternative to traditional grid connection.
Implementation Phase (2023-2027)
Milestone 4: By 2027, networks will buy grid services from customer power systems as an alternative to grid investment. This includes network orchestration using distributed energy resources on a dynamic, locational basis, resulting in one-third of customers selling their distributed energy resources services to networks, directly or through their agents.

6.3 Key principles for future market and regulatory design

As per our assessment framework (described in Section 3), KPMG considered the following market and regulatory design principles in relation to setting network tariffs necessary in order to achieve market competitiveness and efficiency for DER-related products and services:

- Provide compensation for network value delivered by DER;
- Promote efficient investment in DER;
- Allocate costs based on use and causality;
- Customers are provided with tariffs which they understand and able to respond to; and
- Alignment of risks and rewards.

6.4 Key potential constraints and risks

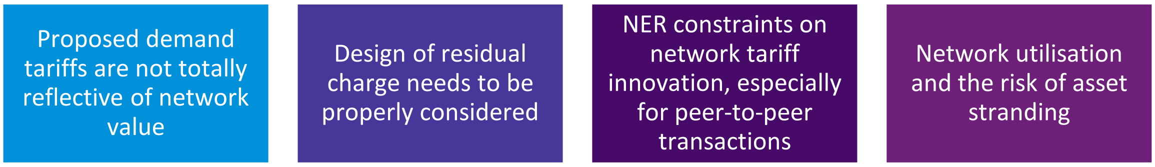
Network tariffs will be the primary signal of the value from DER services. The value of the network component from DER in terms of deferring capital expenditure could in theory be signalled through the structure of network charges. For example, when a customer makes a demand response decision, it will automatically receive a “payment” corresponding to the network value (through lower network charges). Whether that payment reflects the true value will depend on whether the network charge is fully cost reflective. It will also depend on how retailers pass through such tariffs in their retail offers.

In addition, the greater the response and change in behaviour generated by the cost reflectivity of the network tariff will, to an extent, determine the need for distributors to seek to contract and procure DER services. If network costs are not cost reflective, the DNSP may need to make supplemental payments via NSS to customers in order to obtain the required response to address network limitations. This approach is currently being used in mechanisms such as critical peak rebates, where a customer received an additional reward for undertaking specific defined actions.

However, network tariffs across Australia are not cost reflective. There are moves towards more cost-reflective tariffs following the AEMC rule change; however, it is likely to take some time to transition towards cost reflective tariffs. In general, a move towards greater cost reflectivity in network tariffs would assist in better reflecting and rewarding the network value from DER, thereby providing for improved price signals for investors (consumers) in DER.

This section presents our assessment of the current framework (and changes identified under the Roadmap) ability to promote efficiency in DER services and the development of competitive markets consistent with the assessment criteria presented above.

Figure 8. Networks tariffs constraints and risks



6.4.1 Proposed demand tariffs are not totally reflective of network value

The "demand" tariffs proposed by several DNSPs in their recent tariff structure statements – and envisaged to continue under the Roadmap - are designed to charge a consumer at the time of their own "non-coincident" maximum demand, rather than at the time of the network's "coincident" maximum demand.[52] Since it is coincident demand that drives network augmentation costs, such tariffs are only cost-reflective to the extent that the coincident and non-coincident maximum demands happen to occur at the same time. For residential customers, this is the exception rather than the rule.

These demand tariffs encourage consumers to reduce their non-coincident demand, and this can be done quite effectively using batteries fitted with the appropriate controller algorithm. Therefore, these demand tariffs encourage battery purchases, but also encourage battery cycling regimes which do little to reduce network peak demands. Indeed, it is quite plausible that many consumer batteries could actually be charging over the coincident maximum demand, thus adding to demand and network costs.

We consider that further consideration is needed to understand why DNSPs have opted for non-coincident – rather than coincident – demand tariffs.[53] It has been asserted that coincident demand charges are too complex for customers to understand and for retailers to implement. We acknowledge the complexity, compared to existing flat tariffs, but do not find non-coincident demand structures to be any simpler, for consumers at least.

Indeed, most consumers will understand and expect – through experience of buying services such as hotel rooms and airline travel – that prices will be highest at times of high overall demand. Furthermore, electricity consumers will be aware that distribution networks often struggle at times of very hot weather (and associated high demand), with companies and governments commonly urging consumers to voluntarily reduce their demand at such times. In this regard, we consider coincident demand charging to be fairly natural and intuitive for consumers; non-coincident demand charging is the opposite.

Therefore embedding the concept of charging demand on a non-coincident basis creates a risk of inefficient signals to investors in DER and could limit the ability of network tariffs to adequately signal the value of DER in the future.

6.4.2 The design of the residual charge needs to be properly considered

Notwithstanding the actual level of LRMC, there will likely always be a need for a "residual charge" to recover any shortfall between a distributor's target revenue and LRMC-tariff income. At the extreme, if

[52] Coincident demand is the energy demand required by a given customer or class of customers during a particular time period such as the system peak demand. Loosely speaking, it refers to demand among a group of customers that coincides with total demand on the system at that time. Non-coincident demand is the individual customer maximum demand at any time period.

[53] We note that such tariff structures are long-standing for very large customers but, unlike with small customers, the peak demands of such large customers actually drive network peaks. Therefore, this does not set a precedent for why demand charges for residential customers are levied on a non-coincident basis.

LRMC is truly zero, these residual charges must recover all target revenue. This raises a number of questions for distributors in how these residual tariffs should be structured. It is also important to consider how these residual charges are designed going forward under a high DER scenario, especially whether the design of the residual charges creates an incentive for users to disconnect from the grid.

Residual charges are intended for revenue recovery, and are not meant to incentivise specific actions by network users. To the extent that users respond to them, there could be additional costs for the system, but there could also be incidental benefits from this response.

Currently, residual charges are recovered through a common, fixed charge applied to all customers, irrespective of usage. In recent years, some distribution networks have increased the size of these charges. In addition, some residual charges have been introduced due to governments deciding to recover costs of schemes and environmental policies through network tariffs (such as feed in tariffs).

Such fixed residual charges are often considered to be inequitable as customers with high usage pay the same as those customers who place less stress on the network. This issue could become more important in the future if flat or declining growth results in a low LRMC price signal.[54]

We consider that the increase in availability and affordability of smaller scale generation (and in future, potentially storage) requires reconsideration regarding the design and application of residual charges in network pricing. This is due to the fact that such technologies will substantially shift the price elasticity of customers through potentially providing a credible means to disconnect from the grid. In addition, the availability of DER provides a framework for considering the value that the consumer obtains from grid connection or the capacity they demand.

The value of grid connection is the cost of the DER (specifically, with current technologies, PV, batteries and load management devices) that the consumer would need to supply themselves on a standalone basis. A large consumer will obviously need to spend more to disconnect than a low consumption consumer. Therefore, there could be merit in considering how residual charges should vary in proportion to the customer’s demand.

However, if residual charges continue to be charged on a fixed basis, customers with low usage will – at some point – find it worthwhile disconnecting from the grid and, increasingly, the grid will be de-populated as the residual charge increases. The Roadmap recognises this risk, from fixed charges, and proposes a discounted tariff for those liable to disconnect from the grid.

This is an important start, but we consider more analysis is needed regarding considering how best to structure residual charges to all customers. Some consumers can more easily reduce their net demand, or their peak net demand, and more are likely to be able to do so in future. Residual charges levied on net demand or peak net demand, or discounted tariffs for those customers most likely to disconnect, will fall more on users who do not have these technologies. This could lead to potentially adverse distributional effects.

6.4.3 NER constraints on network tariff innovation, especially for peer-to-peer transactions

In addition to the current approach for setting network tariffs, specific clauses of the NER may be considered prohibitive to the future development of a competitive and efficient market for DER. For

[54] Even if demand is falling, this does not mean that LRMC is zero. Network assets have a finite life. When they reach the end of their useful life, a decision must be made as to whether to replace them and, if so, with what size asset. This will depend upon the demand level – and projections of demand growth – at that time. Other things being equal, a higher demand level will mean an increase in replacement cost. Thus, even if demand is falling, LRMC is non-zero.

example, clause 6.1.4 of the NER requires distributors to not charge a network user for exporting electricity generated by that user into the network. We note however, that this clause helps to achieve consistency with generators connected to the transmission network that are not charged network charges.

Clause 6.18.4 of the NER requires those consumers deemed to have a similar connection and usage profile to be treated on an equal basis. Specifically, consumers with "micro-generation" facilities are to be treated no less favourably than those consumers without such facilities and with a similar load profile. While there are strong reasons in support of the inclusion of these clauses under the current rules (e.g. ensuring a fair and equitable outcome for all consumers), as we see continued penetration of DER, and the evolution of market DER products and services, these clauses may become outdated.

For example, where a consumer with a DER is considered to provide value to the network, the current rules would appear to prohibit this consumer from sharing in that value (e.g. in the form of lower network tariffs). This clause also limits a distributor's ability to develop a specialised tariff structure recognising the existence of a DER as has been the case in South Australia, where the AER recently refused the approval of SA Power Networks' proposed Solar PV tariff (see Box 3).

Similarly, an inability to set network usage charges for those exporting into a network may have implications for any possible platform facilitating peer-to-peer transactions. This market platform would allow consumers with a DER to sell their energy production to another market participant (e.g. residential or C&I customers, retailers). Subject to the structure of any agreement between participants, in order to reflect the true cost of supply inclusive of the use of a distributor's network, it may be necessary for such export charges to better reflect the actual proportion of the network used in such transactions. This will depend on the impact of such transactions on network operations and capacity.

Box 3: Case Study – SA Power Networks' Solar PV Tariffs

As part of its 2015-16 Pricing Proposal to the AER, SA Power Networks proposed a new residential tariff to apply to those customers with solar PV. This proposal was based on the premise that residential customers with solar PV have a different load profile to those who do not, in the order of 20% less favourable. SA Power Networks noted that the new tariff would ensure residential consumers with solar PV will pay a fair price for the capacity they require while also recognising the benefits they deliver to the network (in the form of reduced demand).

The AER found SA Power Network's proposal for a Solar PV tariff did not comply with the NER. Specifically, clause 6.18.4(a)(3) requires that retail customers with micro-generation facilities be treated no less favourably than retail customers without such facilities but with a similar load profile.

Using data provided by SA Power Networks, the AER found there not to be sufficiently dissimilar load profiles between these customer types, and therefore little justification for introducing a new tariff.

This decision was challenged by SA Power Networks in the Federal Court under judicial review which found in favour of the AER's original determination. The Court dismissed SA Power Networks' application for judicial review, recognising that the AER had correctly applied the NER and did not make an error in its decision.

Generally, we advise that further analysis and consideration is needed on the appropriate tariff approach for peer-to-peer transactions. For example, there is a strong rationale for arguing that such transactions should not be levied the transmission component to the distribution charge. To date, peer-to-peer transactional models have been primarily driven by the preferences for locally sourced renewable energy. However, the UK platform is starting to look at how to also capture potential savings in distribution network costs caused by peer-to-peer transactions.

We understand that the UK platform operated by Open Utility is seeking changes to the distribution use of system (DUOS) methodology so that local generators and consumers who are matching on a half-hourly basis, would only pay for the extent of the distribution network that they use.[55] This would be a limited form of locational network pricing only applicable to peer-to-peer transactions. Open Utility argue that such a change could unlock the full potential of peer-to-peer energy and realise a future where grid usage is fairly charged.

Greater analysis and debate on the appropriate charging framework for DER, including peer-to-peer transactions, is required. Providing a locational signal to residential and small business consumers in the distribution network is challenging due to the shared nature of many of the assets they use, which will make it difficult to attribute precisely the cost of the assets to specific peer-to-peer transactions. However, this by itself is not a reason to not explore the issues. Such analysis and debate should occur prior to the peer-to-peer market start to remove any barriers from commercial development of those platforms, especially as we suspect that changes to the NER pricing principles will be needed.

6.4.4 Network utilisation and the risk of asset stranding

A further consideration is whether there is any relationship between the risk of asset stranding under a high DER scenario and the DNSPs' approach to tariff reform. As we continue to see greater penetration of DER in the network, and consumers becoming more and more self-sufficient for their energy supply, this risk will gradually increase over time. To mitigate against this risk, networks could seek to have tariffs with the objective of discouraging the development and deployment of DERs that compete with otherwise sunk network assets.

This potential behaviour will, to an extent, depend on how the economic regulatory framework values network utilisation (which is an important factor in AER benchmarking techniques) and treats stranded assets. If distributors have confidence that there is no risk of stranded assets being removed from the regulatory asset base (RAB) then there would be no influence on tariff design. While this is the case today under the current regulatory framework, we consider that it could be naïve to consider that this is a permanent feature under future developments. Given that, we advise that there could be merit in initiating discussions on how to manage the potential risk of stranded assets. Possible options to consider include:

- More flexible use of depreciation to either pay off stranded assets faster or delay payment until utilisation improves. A distributor would be allowed to nominate different depreciation schedules for the same type of asset;
- Removal of stranded assets from the RAB into a separate fund. A distributor would be allowed to securitise/refinance those assets and charge costs to consumers. These assets may be refinanced at a lower rate than weighted average cost of capital (WACC) but at a fixed rate. This approach was used in the US to manage utilities' stranded assets that became uneconomical as the result of deregulation ("transition bonds"). This effectively allowed shareholders to "cash in" future cash-flow at a net present value (NPV) loss in order to remove regulatory risks; and
- Require customers who are directly responsible for stranded assets by going off-grid to "buyout" those network assets dedicated to supplying that customer.[56] In principle, this would not be an

[55] A glimpse into the future of Britain's energy economy – Open Utility December 2016.
[56] Further, such a move by a customer may expose a retailer to bad debt expense. As a conduit for payments to a DNSP, a retailer may find itself in a position where it cannot recover its own cost of supply, as well as pass through a DNSP's charges.

"exit fee" as the assets would be removed from the RAB. This approach would not directly solve the issues of under-utilisation of a distributor's assets and would likely raise various questions, including:

- What is the definition of "dedicated assets"?
- Is payment to be a one-off fee or could other financing arrangements be made available?
- How would this would be achieved legally under the current standard contract terms?

We consider that it is important to view this not as a zero sum issue between distributor and consumers and that there are potential approaches which deliver benefits to all parties. For example, through incentivising distributors to self-identify stranded assets and/or share in the benefits associated with savings from removing assets from the RAB. It is likely to be easier to have such discussions now, in advance of any material changes in network utilisation following customer investment in DER.

6.5 Advice and future work

6.5.1 Advice

As noted in the current arrangements described above, the AEMC's 2014 rule determination resulted in significant changes to the adopted approach to setting network tariffs. While not specifically a new change, the requirement for distributors to establish their tariff structures up front for the proceeding five-year regulatory period as part of their TSS may impede a distributor's ability to provide long-term price signals to the market.

This inflexibility in the arrangement may contribute to the real risk already in the market today, whereby consumers are making investment decisions based solely on the current tariffs (and reward) without due consideration to future tariff structures and/or changes in those structures as the network continues to evolve. This evolution, and therefore risk, may result in a reduction in the payoff for a particular investment. The danger of not providing long term certainty and predictability to DER investors is material given the recent opposition of solar PV groups to tariff reform. In conclusion, uncertainty about network tariff reform is likely to impede DER market development.

We recognise that tariff reform is difficult and contentious and relies heavily on getting a social licence from community and governments in order to be effective. Even once introduced, the new tariffs could ramp up only gradually, in order to avoid price shocks and customer resistance. Therefore, it is important to be practical and recognise that alternative mechanisms will be needed to transfer network value to the DER owner.

While accepting the issues with implementing tariff reform, we consider that there are limitations with the current pricing principles that will impede the development of DER in addition to the fact that, to date, there has been limited consideration on the appropriate tariff structures for DER transactions, such as peer-to-peer. The five year lag between tariff structure statements creates a material risk that tariff reforms fail to keep place with market developments.

It is also important to recognise the inter-relationship between network tariff reform and the DNSP procurement of DER. A distributor's incentives are to beat the AER's forecasts, i.e. to embed high forecast peak demand growth in the capital expenditure projections and then ensure that their actual expenditure comes under such projections.

Cost-reflective tariffs on the other hand should bring down peak demand growth. This will be reflected in both forecasts and actuals and, as a result, confer no financial advantage on a distributor. A distributor therefore requires a fast, tactical mechanism to reduce demand growth within a regulatory period, allowing for forecast capital expenditure to be avoided or delayed. The current tariff structures cannot do this as they are only introduced (or amended) slowly. A distributor would therefore prefer to use a direct procurement approach, which can be targeted and introduced quickly. However over time, the procurement approach may become an established and permanent feature and remove the need to pursue greater cost reflective tariffs.

6.5.2 Future work

Key areas for future work include:

- Development of the regulatory and market arrangements to facilitate peer-to-peer transactions. This is likely to require considering how the costs across the electricity supply chain, including government scheme costs, are levied on such transactions in addition to issues relating to customer protection and settlement. For example, whether such transactions should be exempt from paying transmission charges or retailer obligations (renewable energy or energy efficiency certificates, for example).
- A review of the current Rules that could prevent different network tariffs being considered (e.g. export tariffs under NER clause 6.4).
- An options study on how to address the potential risk of stranded assets under a high DER scenario.[57]
- A review of pricing principles for residual network charges to remove the negative distribution effects on those consumers who cannot afford to own DER resources and to reduce the incentive to go off-grid.[58]

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[57] The Roadmap has modelled a scenario that partially addresses this risk where electrification of transport could make a substantial contribution to efficient network capacity utilisation. (See page 34)

[58] The Roadmap recognises this risk when it states *"Emergence of the potential for off grid and competition in network services to lead to an unplanned and disruptive break down of the funding of the commons of a shared network service capable of integrating efficient levels of centralised generation and distributed energy resources that meet customer needs"* (page 21). The Roadmap proposes that *"By 2027, customer interests are protected by strong and effective customer safety net arrangements which underpin confident participation in new service markets, while protecting vulnerable customers from hardship in a targeted way."* (page 21)

7 Distribution system operation

Distribution system operation is currently a regulated function of DNSPs. This section considers whether the current integration of roles between the DSO and DNO is a material risk to the development of market competitiveness and efficiency for DER-related products and services.

Key findings

1. A DNSP's financial interest in DER services does not necessarily depend on whether the DNSP owns the DER asset (either directly or indirectly through related parties). A financial interest could still exist through:
   a. the procurement of services from DER owners by the DNSP depending on the design of those contracts and how the associated costs are treated under the economic regulatory framework
   b. DNSP investment in a market platform (such as a dNOM) to purchase DER for network support services
   c. a DNSP incurring costs associated with developing its own products to procure DER directly from customers (i.e. investment in automation control technology).
2. Where the DNSP has a financial interest in the usage of DER, this can in theory lead to conflicts regarding how it operates its distribution system. This is unlikely to be a material problem in the short term given current capability in the network. However, there could be a risk in the future, depending on the extent to which DER and smart technologies enable distributors to become more active in system operations needing to balance energy flows at a distribution level. In this future scenario, a DNSP may find itself conflicted between the use of its own DER and that of another consumer or market actor.
3. There will be advantages and disadvantages to separating the DSO role from the DNO role within the DNSP. Consideration on this issue would provide certainty for the market, including identifying the potential future circumstances where separation between the distribution system operation and network ownership would be better for customer outcomes.
4. Specifically, where a DNSP has a positive financial interest it will naturally favour its own DER over the use of others connected within the location. Even if there is no financial interest, any perception of a conflict or lack of independence will dampen market confidence and investment in DER.

7.1 Current arrangements

As noted in Section 2.4, the current role of a DNSP may be broken into two, as a DNO (distribution network owner) and as a DSO (distribution system operator). Within these roles, a DNSP will undertake a range of functions relating to the provision of distribution services, including:

- Measuring or forecasting the demand for distribution services (i.e. consumer loads and the associated network flows) – a DSO function;
- Acquiring the distribution inputs (network capacity and/or NSS) needed to supply this demand reliably – a DSO function;

- Identifying and designing potential network augmentation projects to help meet future distribution requirements – a DSO function; and
- Funding, building, maintaining and operating associated network assets – a DNO function.

These roles can occur in both planning and operational timescales. For example, "acquiring the distribution inputs" involves:

- In planning timescales, selecting a preferred network augmentation project or contracting with NSS providers; and
- In operational timescales, switching network assets or controlling (directly or indirectly) DERs that are providing NSS.

7.2 ENA/CSIRO Roadmap

While the Roadmap does not explicitly discuss the separation of a DNSP's existing roles and responsibilities, it does recognise the diversity and number of new sources of load and generation at the edge of the distribution network has the potential to disrupt the traditional operating model. The Roadmap also recognises the need for regulatory frameworks to define and accommodate potential approaches to developing distribution system roles and responsibilities in light of the development of new markets and tools supporting integration of DER.

In maintaining their existing functions, a DNSP will be required to adopt new protection systems and forecasting and planning approaches, including the ability to anticipate distribution system constraints, accounting for the high penetration of DER in the market. Such new protection systems may be incorporated as a component of an integrated control and monitoring architecture, and may contribute to the connection of new, diverse technologies to the network.

Further, as described in Section 4.2, the ENA/CSIRO foresee the development of ANO tools to support the efficient management of the electricity network moving forward. These tools may naturally arise as an extension of current utility functions and are considered as a foundation to the continued safe, reliable and efficient operation of the network in a high DER environment.

Importantly, these tools are seen as part of a broader, *"coordinated and automated process for network management – for example assisting in managing voltage, excursions, responding to loading unbalance in, real time or managing short term constraints."* Having only initially identified a NSS market as part of the Roadmap, the ENA/CSIRO have not explicitly defined a role for the DSO in the NSS market.

> *"The Roadmap distinguishes the systemic application of advanced new tools for this purpose as Advanced Network Optimisation (ANO). This avoids the lack of clarity that can arise by using the term Distribution System Operator (DSO) as it is defined in many ways in the international literature. The Roadmap recognises that ANO technological functions will be increasingly necessary to ensure efficient management of Australian electricity networks that have high levels of renewable energy and distributed energy resources. It also recognises that many ANO functions may naturally arise as an extension of current utility functions."*[59]

The Roadmap also noted that communication between the Independent Market Operator[60] and distribution system control functionality in real time using automated signals is critical if coordination and optimisation of the system is to be achieved. This will facilitate the system-wide active

[59] ENA/CSIRO, Electricity Network Transformation Roadmap: Final Report, April 2017.
[60] The Roadmap does not define what is meant by the term Independent Market Operator. We have interpreted this to mean the wholesale market operator role, currently performed by AEMO.

management of network, generation, demand and other services as utility and rooftop scale variable renewable generation grows to make up a much larger share of total generation.

7.3 Key principles for future market and regulatory design

As per our assessment framework (described in Section 3), KPMG consider the following market and regulatory design principles in relation to distribution system operation necessary in order to achieve market competitiveness and efficiency for DER-related products and services:

- Responsibilities for the safety and reliability of the local distribution system are clearly specified, transparent and allocated to the most appropriate party;
- The objective of the DSO is to meet the needs of network users at the lowest, long-run cost. The current regulatory framework has been designed in order to achieve this; and
- Conflicts of interest between the DSO role and related business roles, including its role as DNO, should be avoided or managed accordingly.

7.4 Potential constraints and risks

If distribution system operation becomes more complex and uncertain under a high DER scenario, there could be potential conflicts and inefficiencies if DSO and DNO roles remain integrated within DNSPs' regulated businesses. These conflicts and inefficiencies will negatively impact the ability to achieve those principles outlined above This section explores the following four issues as shown in Figure 9.

Figure 9. Constraints and risks – DSO

7.4.1 DNSP's transition to becoming an active DSO

With the exception of solar PV, there has been relatively little uptake to date of DER across Australia's distribution networks. This is primarily a historical reflection of the costs associated with investing in such technologies. As a result, there is significant scope for further DER penetration across Australia's distribution networks as the cost of such technologies reduces further, and as new technologies become commercially viable for consumers.

This increase in DER may occur without significant augmentation of the distribution network and therefore largely be accommodated within the existing network capacity. In a high DER scenario, this may result in a significant volume of transactions occurring without risks to the operation of a DSO's network. These transactions are not confined to the direct procurement of NSS by a DSO, and may include peer-to-peer trading of energy related products and retailer/aggregator participation in the wholesale energy market on behalf of consumers.

In addition, it is not clear whether a high deployment of DER will make network flows unpredictable and therefore distribution system operation more uncertain and volatile. DER will likely make customers more responsive which could remove some of the operational need for active control by distributors. The key will be in providing the right signals to the market to foster an efficient response. Given the likelihood of a high level of automation to DER given available technology, forecasting flows and customer behaviour should become more predictable.

Therefore, the extent to which DER requires distributors to move from a passive role to one of responsibility for actively balancing energy flows at a distribution level, remains unclear. For any given network, and more specifically any given point on a network, a tipping point exists where the potential volume of transactions leads to network constraints as a result of the operation of DER. For example, these constraints may arise as a result of reverse power flows affecting a DSO's voltage control or more generally as flows approach the capacity of network assets.

Past this tipping point, the role of the DSO would be to actively manage the flows and dispatch of DER to maintain system security and operations. In doing so, it would seek full use of smart techniques to create value for the wider electricity system, e.g. by undertaking an element of regional balancing and providing reserve and frequency response services to the national system operator.[61]

It is important to be aware that the DNSP, in making the transition to becoming a more active DSO, could happen under current Rules without any policy considerations. A DNSP could invest funds into the needed technology for more active system operation without the approval of the regulator, if the DNSP funds that investment from its revenue allowance. This is due to the discretion permitted under the revenue rules. It will only become an issue for regulatory approval if the DNSP is seeking additional funds.

There is nothing to prevent the distributors from making a transition to become more active DSOs now, or at least in the early stages of system operation.[62] However, further assessment is warranted as to whether the continued integration of DSO-DNO roles will lead to an optimal outcome for the market over the long term.

7.4.2 DSO preference towards its own products

As part of its core regulated business, a DNSP may own and operate its own DER. For example, "controlled load" is essentially a DER technology, providing NSS to the DSO. Associated assets will be included in the DNSP's regulated asset base. Thus, a DNSP can earn a guaranteed regulated return on such DER, whereas DER that is developed and owned by consumers or other parties does not have such a guarantee. This may create a barrier to these competitive alternatives emerging.

Further in the context of direct procurement, whether, in selecting between products that its own organisation has developed versus those products developed by another party (consumer, retailer or aggregator), there is the potential for a DSO to naturally prefer its own products because:

- Such products are more aligned with the cultural preferences of the DSO;
- There may be a psychological preference to select one's own products given that the business will have a better understanding of its own products; and
- Where sunk costs are involved in product development, the DSO might select this product in order to recover these sunk costs.

These issues also arise in the DSO-DNO within the DNSP context, since network options are developed by the DNSP, whereas non-network options may have been developed by retailers or other parties. Indeed, because the differences between network and non-network options are likely to be more

[61] Such services will become increasingly important to maintaining a stable, balanced national electricity system as conventional 'synchronous' generation associated with coal and gas fired power stations gives way to higher volumes of intermittent renewable generation technologies.

[62] Especially if they do not need to seek AER approval for associated expenditure.

marked than the differences between DSO-developed and consumer / retailer-developed NSS products, the issue is likely to be exacerbated.

The issue of a DSO's preference – perceived or actual – between network and non-network options has been recognised by the market for a long time and various mechanisms – in particular the RIT-D process – have been introduced to address it. However, the issue has historically not been a major one, perhaps, because the scope for developing economic non-network options has been fairly limited. This might well change in the future, with the emergence of DERs, such that non-network options might come to compete with, or even dominate, network options.

7.4.3 Revenue regulation

Currently, DNSPs are subject to revenue regulation, which places a cap on the total distribution revenue that a DNSP can obtain through network tariffs. The cap is based on an estimate of the efficient cost of providing distribution services; or, put another way, the total cost of distribution inputs.

As discussed, distribution inputs may be in the form of network capacity or NSS. Because the DSO and DNO roles are integrated, DNSPs own their own network assets and so the cost of network capacity is primarily in the form of capital expenditure. On the other hand, DNSPs will generally not own the DER assets that provide NSS (indeed, they might be prohibited from doing so), and so will instead indirectly fund the DER capital costs through DSO payments to NSS providers. Therefore, from the DSO perspective, NSS costs primarily arise in the form of operational expenditure.

An ideal regulatory framework avoids introducing any bias between capital expenditure and operating expenditure, so that a DSO will select the lowest cost option, irrespective of the cost category. However, this is not straightforward to achieve in practice. This is a long-running issue that has been progressively addressed through changes to the regulatory design. Nevertheless, there are some concerns that a residual preference towards capital expenditure remains (as discussed further in Section 9.4.1). To the extent that this is true, this will see DSOs selecting network options.

If this issue cannot be satisfactorily addressed through regulatory design, it might instead be addressable through DSO-DNO separation. Since the DNO, and not the DSO, owns the network assets, the DSO should regard procuring a network option as an operating expenditure cost rather than a capital expenditure cost. However, this begs the question of exactly how the DSO and DNO would be regulated under such a separation.[63]

7.4.4 Market transparency

The issue of market transparency, also discussed in previous sections, similarly applies to the DSO-DNO issue. The DNO, in developing augmentation projects, inevitably is provided with a vast amount of information and guidance from the DSO around distribution requirements and network capabilities. Not all of this information is necessarily relevant to NSS providers (e.g. that relating to the more arcane aspects of network design and operation such as protection systems and fault levels) but much of it will be relevant. As discussed in Section 4 on DNSP procurement, where there is close integration between the developer of a NSS product and the procurer, it will be very difficult to practically address the potential risks of any information asymmetry.

[63] There are a number of different separation models across the world from which from to draw lessons, for example, the separation of Victorian transmission might provide some lessons and insights in this regard.

7.5 Advice and future work

7.5.1 Advice

There will be advantages and disadvantages to separating the DSO role from the DNO role within a DNSP. We are not necessarily advocating for separation, just that early consideration of this issue would provide certainty for the market, including identifying the circumstances where separation would be better for customer outcomes.

In considering separation options, benefits need to be quantified and compared (around removing the conflicts and biases discussed) against costs (e.g. higher management or transaction costs, loss of "vertical externalities" such as a shared knowledge pool, extra cost of designing and complying with new regulations). More specifically, in considering the possible separation of a DNSP into its two roles as DNO and DSO, there is a need to consider the following:

- The exact point of delineation between the two roles. For example, who is responsible for developing the network augmentation options;
- The form of separation of DNO and DSO (discussed further below). This separation may be informational ("Chinese wall"), financial, managerial and/or corporate.
- How to regulate the two differing roles moving forward and if there is financial separation between DNO and DSO, identification of the potential financial implications in setting revenues and prices for each; and
- How to deal with existing network assets.

The perception of independence will be crucial to the success of any future market for DER-related products and services. If DNSPs choose to develop and own DER (as part of their core businesses), those conflicts and risks identified above are likely to grow and future separation of DER ownership from a DSO may become more difficult and complex. Earlier separation may therefore be justified in order to avoid these future costs.

Should the role of the DSO become one of increasing importance to the overall function of a market for DER (and therefore a driver of separation) and importantly the market's competitiveness and efficiency, the treatment of any existing DER assets owned and operated by a DNSP must be considered. While the AEMC's recent metering contestability rule change will ensure effective transition of metering services to competitive providers, a similar arrangement for DNSP-owned DER (e.g. load control) is currently unclear and warrants further consideration.

Finally, where the benefits and costs of separation are dependent on the level of DER penetration, one could estimate a "breakeven" level of DER penetration at which separation becomes desirable. In any case, a transition pathway facilitating any proposed structural changes to the role of a DNSP must be developed. If structural change is favoured, it should be indicated to the market as soon as possible in order to avoid unnecessary investment in the infrastructure or systems.

Section 6.4.4 discussed the interactions between the potential risk of existing network assets becoming stranded and the DNSPs' approach to network tariff development. Consideration of the potential for stranded assets and possible changes to the regulatory treatment of such assets could, in theory, also influence how DNSPs view the development of the DER.

We see potentially two opposing effects. Firstly, to mitigate the risk that existing network assets become stranded, DNSPs might take steps to slow the development of DERs, possibly through declining to purchase NSS from DERs. This may not be totally effective if the demand for DERs is to be driven by non-economic factors.

The opposing effect, though, is that if DNSPs do not purchase NSS, they will instead be forced to build new network capacity to meet demand growth and to replace existing network assets reaching the end of life. When existing assets are at risk of stranding, it would be preferable to avoid adding further to the asset base.

The net effect of these opposing forces is unclear: should they cause a DNSP to discourage or encourage NSS development? The Roadmap makes it clear that DNSPs welcome the development of DER and recognise their value for the network. Either way, any preference may be removed by separating the DSO and DNO, so that the stranded asset risk is no longer a DSO concern that will make the decisions relevant to the efficient development of DER.

7.5.2 Future work

Key areas for future work include:

- An assessment of networks' current ability to manage an increase in DER penetration and whether to develop threshold tests to identify where DER penetration could have a material impact on distribution network security and power quality. This could aid in informing regulatory assessment of expenditure proposals.
- Discussion and identification of the circumstances where separation of distribution system operation role and the network owner would be necessary and consideration of how to implement such separation.
- Establishing clear and effective operational procedures and boundaries in relation to how a DNSP may use DER (this includes a framework for governing how a DNSP would be allowed to curtail DER when necessary to maintain network security).
- Establishing a framework for collecting and sharing data across market participants. It will be essential for networks to have visibility of the physical operation of DER participating in the wholesale market and other commercial platforms. Similarly, retailers will need to know when distribution businesses call on DER services and control output at DER sites as this impacts on their hedging positions and liabilities to the wholesale markets. The industry should come together and develop a common framework for information sharing which recognises all interests and information needs.

8 Network access and connection

Network connection and access are inter-related concepts. Having connected, access to the network is not necessarily guaranteed. This section considers whether the current arrangements in which a DER secures access and connection to a distribution network creates a material risk to the development of a competitive and efficient market for DER-related products and services.

Key findings

1. DER technologies, such as PV and batteries, have different technical characteristics to load and different impacts on the safety and quality of distribution. Therefore, rights and obligations around connecting these technologies behind the meter may likely need to differ from conventional load connections (e.g. a new air-conditioner). However, these rights and obligations are yet to be fully developed, creating uncertainty for DNSPs and consumers.
2. Any new connection standards should be developed and applied as soon as possible, as opposed to simply waiting for potential problems with existing arrangements to emerge. These should set out simple, fair and transparent connection rights. Obligations and standards are therefore required in order to ensure all DER are able to connect to a distributor's network with minimum transaction costs. Similarly, where a DER connection is either restricted or rationed, for example due to limited hosting capacity, such policies must be transparent and accessible to all potential investors in DER.
3. Where connection of new generating equipment must be limited, there needs to be some transparency around how, when and where that might occur. For example, the publication of "hosting capacity" information indicates where constraints are approaching.
4. Reliability standards apply to conventional distribution service, supplying consumer load. There are no corresponding export reliability standards for the new "export" distribution service of accepting consumer exports onto the grid for delivery to HV or a transmission network. Thus, an exporting consumer's "access" to the network is uncertain. We recommend that consideration be given to whether some form of "export reliability standard" is required under a high DER scenario.
5. Providing a DNSP with discretion to strike the right balance between market efficiency and safety/security of a network in the connection agreements may not promote the right outcomes for the market more broadly. This is because there may not be any incentive for the DNSP to take into account market implications and benefits from DER. As a result, any new connection arrangements for DER must reflect market-wide considerations to best promote the NEO.

8.1 Current Arrangements

For historical reasons, different access and connection regimes are in place depending upon the type of connected party. A consumer enjoys a firmness of access in accordance with jurisdictional reliability standards, which specify (directly or indirectly) how frequently a consumer's imports may be curtailed. Consumers are free to connect new load devices behind the meter (as long as this does not cause any stated connection capacity to be exceeded[64]), and the DNSP is responsible for expanding network capacity as necessary to maintain reliability standards in the face of this load growth.

Similarly, a DNSP is responsible for expanding the capacity of transmission interconnection points to ensure that the necessary amount of power can be drawn from the transmission network to meet distribution network load. By implication, the same reliability standards apply since, if a transmission interconnection point is overloaded, some downstream consumers will need to be interrupted in order to restore network security.

However, there are no corresponding access or reliability standards for distributed generators. New embedded generators require DNSP permission to connect and, having connected, may be subject to access restrictions. Large embedded generators (above 30MW) are subject to AEMO dispatch and can be constrained by AEMO to prevent overloads on the distribution or transmission networks. The current reliability standards of the framework are based on one-directional flows.

Connection of DER, such as rooftop solar PV or household batteries, is covered by Part 5A of the NER. The connection process depends upon whether any augmentation, or other substantial modification, of the distribution network is required to accommodate the new connection. If no augmentation is required, the DNSP must provide the connection in accordance with an AER-approved "model standing offer". If, on the other hand, augmentation is required, the DNSP is not obliged to make any standing offer (although it may choose to) and the connection terms are instead negotiated. Whether such connections need to pay an upfront payment (capital contribution) depends upon whether the incremental cost is more than the incremental revenue (cost-revenue test).[65]

We have not investigated how this framework is applied in practice. However, we would expect that it would be difficult for a consumer to connect a DER on parts of the network where augmentation would be needed, i.e. where the "hosting capacity" for such resources has already been exhausted. Presumably, the DNSP could undertake augmentation to create new hosting capacity in such areas. However, we are not aware of any rules or regulations that oblige the DNSP to do this, and the regulatory framework creates incentives on DNSPs to avoid incurring any unnecessary cost. The current arrangements therefore provide for:

1. Where there is adequate hosting capacity, connection of a DER may be seen as relatively straightforward and involves no subsequent restrictions on access specific to that resource;
2. Where there is inadequate hosting capacity, connection of a DER may not be commercially viable, at least for small consumers; and
3. A DNSP is not obliged to augment the network to provide new hosting capacity where this has been exhausted, and is financially discouraged from doing so if this would incur significant cost not approved in the regulatory determination.

8.2 ENA/CSIRO Roadmap

A stated driver of the ENA/CSIRO Roadmap are "customers' expectations of a responsive grid, enabling streamlined connections and a 'plug and play' environment supporting their choice of technologies."[66]

[64] For the majority of residential customers, there is no explicit connection capacity.
[65] The intention of Rule 5A is to exclude deep system augmentation charges for retail customers. This operates through the application of a shared network augmentation threshold under which connections are not subject to the shared cost component of the cost-revenue test.
[66] Energy Networks Australia and Commonwealth Scientific and Industrial Research Organisation. Electricity Network Transformation Roadmap Final Report. April 2017.

It is recognised by the ENA/CSIRO the key role networks will play in delivery and connection of an expanding range of products and services consistent with changing technologies and the development of new opportunities benefiting consumers and market participants alike.

Consistent with this driver, a key milestone set by the ENA/CSRIO will see the network service providers taking a more active role in facilitating the introduction of new products and services and streamlining of connection to the grid by 2024. Specifically, connection process are to be streamlined and made nationally consistent. Further, the network service providers are to contribute to industry standards and communication protocols, as well as provide advisory and information services to customers.

Further by 2027, enhanced data analytics and increased use of digital channels enabling improved sharing of information between a network service provider and customer are to contribute to the streamlined connection of products and services by the consumers, aggregators and retailers alike.

We interpret this "plug and play" quality to mean that a consumer can connect DER (including generation devices) behind the meter (BTM) electrical network with no, or minimal, requirement to inform, or obtain permission from, the DNSP. Presumably, local grid security and safety would then be maintained by establishing electrical standards on these devices, just as there are currently on load devices. Indeed, under "plug and play", the distinction between "load" and "generator" disappears. All devices become subject to the same regime.

"Plug and play" therefore represents a longer-term objective and will be achieved by progressively streamlining connection standards including providing for a nationally consistent processes.

8.3 Key principles for future market and regulatory design

As per our assessment criteria (described in Section 3), KPMG considered the following market design and regulatory principles in relation to network access and connection necessary in order to achieve market competitiveness and efficiency for DER-related products and services:

- Access to the network is on an open and non-discriminatory basis;
- Connection and access standards need to be fair, transparent and promote efficient deployment and use of DER[67];
- Network access and connection policies do not unduly constrain the ability of DER to deliver a full range of services; and
- Access and connection requirements support market operations of commercial platforms.

8.4 Potential constraints and risks

A DNSP must be provided with the ability to manage its network, ensuring safe, secure and reliable operation, accounting for the activity of those connected and the power flows (imports and exports) as a result. A DNSP has a range of options to ensure this, including but not limited to, the ability to curtail load – either via a manual switching action or through the automatic operation of protection equipment, or alternatively through direct control of load (such as pool pumps or hot water systems - where a user has opted to give a DNSP additional control over its network imports or exports in order to acquire

[67] Grid Neutrality Principle 5 – Foster open access to the Grid.

network support service. A DNSP could also achieve these tools through third party contracts with aggregators and other parties as an alternative to directly procuring or owning the DER.

To undertake any of these actions, the DNSP will need to have ability to access and control network, generator or consumer devices when required under the terms of the contract. In addition, the DNSP may also seek to protect network security through the network access and connection arrangements which apply to DER. Hence, the access and connection arrangements would cover all DER on the network, while the contractual terms discussed above only apply to those DER which have entered into procurement contracts for the DNSP for NSS. Section 4 dealt with the issues associated with direct procurement. This section explores the potential risks associated with the access and connection arrangements.

There are potentially a number of constraints and risks in achieving the key principles identified above in relation to maintaining a competitive and efficient market for DER-related products and services. These constraints and risks, as shown in Figure 10, will directly impact the ability of a DER owner to secure necessary connection with, and access to, a distributor's network in the provision of services.

Figure 10. Network access and connections – constraints and risks

8.4.1 Managing new technologies

DER technologies such as PV and batteries have different technical characteristics to load and different impacts on the safety and reliability of the distribution network. Similarly, installations of DER can range in size and be larger relative to any load device (e.g. 10 kW rooftop Solar PV). The resulting changes to flows across the network may therefore be significant and highly variable. These factors mean that uncontrolled deployment of DERs could in theory adversely affect local network security. For example, without proper "anti-islanding" protection, a PV system could remain live and operating when the local grid goes down, creating safety issues for repair crews. Even during normal operation, the PV inverter could adversely affect local power quality, either by introducing power harmonics or by causing local network voltage to exceed operating limits.

Load devices have the potential to cause some similar issues. However, electrical standards for load devices and inverters have been developed over time to manage these issues. Similar standards are being considered for new DER technologies such as battery storage. We understand that Standards Australia is working with stakeholders to develop a new draft Australian Standard AS/NZS 5139, Electrical Installations – Safety of battery systems for use in inverter energy systems that will enable the safe installation of battery energy storage systems.

When faced with a new DER technology, a DNSP is faced with evaluating the impact on network security or safety and whether there is a need to consider placing new obligations on connection and access (or in certain extreme cases disallowing connection). The rights and obligations around connecting these technologies behind the meter will likely need to differ from conventional load connections (e.g. a new air-conditioner). Specifically, connection rights and obligations may need to be developed to allow the DNSP (as system operator) to manage these impacts. These might include connection standards around DER control systems (e.g. autonomous voltage-controlling inverters or inverters that can be remotely controlled by the DNSP as the system operator if needed). These rights and obligations are yet to be fully developed, creating uncertainty for both DNSPs and consumers looking to invest in DER.

While DNSPs will need to ensure that updates to their standard connection offers are made over time to accommodate and reflect new BTM generation technologies as they emerge, it is important that such amendments are conducted from the market efficiency perspective rather than the perspective of network operation. Providing a DNSP with discretion to strike the right balance between market efficiency and safety/security of network in the connection agreements may not promote the right outcomes for the market more broadly. As a result, any new connection arrangements for DER must facilitate a market-wide consideration.

8.4.2 Export reliability standards

A question arises as to why a DNSP would pay for the costs of network upgrades, or procured NSS, to deal with export constraints when it can simply deny connection, or limit access, at no cost to itself. Indeed, revenue regulation encourages a DNSP to choose this cheaper alternative. The problem is that, unlike with imports, there is no reliability standard that mandates the level of access that must be provided for exports. Thus, a consumer looking to export to the network from a DER has uncertain "access" to the network under the current arrangements.

At present, DSOs have "load shedding" systems to curtail conventional distribution services when a network would otherwise be overloaded or insecure. However, there are no corresponding systems to curtail exports when needed. Thus, DSOs need to be more conservative in allowing generating devices to connect. An export reliability standard could allow for some level and frequency of curtailment to exports, just as existing reliability standards allow for a certain (albeit very low) level of curtailment to imports.

Conventional reliability standards are informed – implicitly or explicitly – by some assumed Value of Customer Reliability (VCR), which represents the cost to consumers (in $/kWh) of having their supply occasionally curtailed. In relation to exports, the cost of any interruption would primarily be financial – the associated sale of energy would be prevented and some associated income would be lost. Thus, any VCR for exports should reflect the wholesale energy price at the times when curtailment is likely to occur.

For large DER systems that require network approval, the ability to connect may end up operating effectively on a "first come, first served" basis. We understand that some networks have had to turn down solar PV applications due to system constraints. Therefore, the absence of an export reliability standard on a DNSP may create an additional barrier to investment in DER. This may also raise equity concerns, particularly where customers are late in installing DER due to financial barriers, or barriers due to renting or living in an apartment.

At present, the loss in market efficiency from a lack of export standard and guarantee connection for solar PV installation is likely to be quite low reflecting how customers use their solar PVs and its operating profile. Specifically, any export constraints caused by solar PV would likely occur around midday when energy prices are low – suppressed by that same solar PV generation. However, as other DER technologies, such as storage and load management, become widespread, export constraints are likely to arise when wholesale energy prices are much higher. For example, batteries are expected to be discharged – and native load reduced – to maximise value obtained in the wholesale market – and therefore the NEO value of an export standard will be higher.

8.4.3 Managing export constraints

Subject to the volume of DER installed across an individual network, and importantly the type of technologies adopted by consumers, exports from DER could reverse the energy flows across the network. These export flows can cause voltage, protection and thermal network problems. To manage these issues, a DNSP may seek to limit connection or access for new generation in problematic areas of the network. Alternatively, the advanced control and communications capabilities embedded in many new DER technologies could make DER part of the solution rather than (or as well as) part of the problem. For example, local voltage problems can be solved by smart inverters that have voltage control capability. DNSPs could contract with competitive non-network solution providers (e.g. aggregators) to provide voltage management services leveraging these technologies. Thus, DNSPs potentially have the tools – conventional and novel – to manage these issues without resorting to connection or access restrictions.

Voltage and thermal problems are not unique to export constraints. Similar issues arise around import flows. The penetration of air-conditioners over the last decade would have created serious problems for networks if DNSPs had not taken active steps to manage them – primarily by adding new network capacity.

One concern that might arise is if DNSPs make use of new DER technology to restrict access in novel ways. For example, a DNSP might require – as a condition of connection – that an inverter can be remotely controlled by the DNSP so that DERs can effectively be dispatched by the DNSP to manage export (and even import) constraints. This is a concern as it goes against the principles of open and non-discriminatory access.

The DNSP should be required to explore market solutions first to the export constraint before making such decisions to intervene and control access for DER. We do not consider that it would be appropriate for the DNSP to be able to mandate this controllability condition of connection of DER.

Given the possibility that DNSPs may wish to use access and connection agreements to protect network security under a high DER scenario, there needs to be clear and effective operational procedures and boundaries in relation to how a DNSP may use DER (this includes a framework for governing how a DNSP would be allowed to curtail DER when necessary in order to maintain network security).

8.5 Advice and future work

8.5.1 Advice

In any regulatory framework for connection and access, the safety and security of the network must remain paramount. A DNSP should not be obliged to provide any connection or access services that may otherwise compromise the operation of the distribution system. On the other hand, this should not be unfairly used by a DNSP to prevent a DER from connecting and accessing its network, where it meets minimum specifications for connection and where it presents as a credible non-network alternative in response to a known issue. With appropriate forecasting, planning and operational systems, a DNSP should be able to manage its network efficiently to accommodate new DER, as it does currently for new load.

Simple, fair and transparent connection rights, obligations and standards are therefore required in order to ensure all DER are able to connect to a distributor's network with minimum transaction costs. Similarly, where a DER connection is either restricted or rationed, for example due to limited hosting capacity, such policies must be transparent and accessible to all potential investors in DER. By establishing such standards and policies up front, investors (consumers, retailers or aggregators) will be better positioned to make informed (and efficient) decisions regarding their investment and the type of products or services developed.

The importance of having new connection arrangements has been identified by the ENA. For example, the Roadmap promotes streamlining of connection arrangements for customer technologies providing for a nationally consistent process, supporting new market entrants and innovative services.

Importantly, any new connection standards should be developed and applied as soon as possible, as opposed to simply waiting for potential problems with existing arrangements to emerge. Failing to do so may create an unfair bias towards early connectors, with those seeking connection at a later point in time burdened with an unfair share of the costs of the connection. While the rate of technological change will create challenges for DNSPs in maintaining and updating the standard connection offers to reflect all available DER technologies coming onto the system, the current NER oblige DNSPs to maintain these, and the AER has a role in ensuring that they do so effectively.

Moving forward as we see increased exports into the network from DER resources, it may be argued that some form of "export reliability standard" – analogous to existing (import) reliability standard – is required. This new standard would create an obligation on DNSPs to augment their networks to add hosting capacity to accommodate more DER as existing capacity becomes exhausted. The VCR included (implicitly or explicitly) in these standards should reflect the value of such resources in the wholesale energy market at the times when curtailment is likely (i.e. when export flows are at their maximum).

DNSPs will need mechanisms to curtail DER when necessary in order to maintain network security. This is analogous to a form of "export-shedding" at times of constraint across the network. This is likely to require some form of control of individual DERs at a premise. The needed infrastructure (e.g. smart, remotely-controllable inverters) for this could be specified in connection conditions. In establishing this ability, DNSPs should not be permitted to use these control mechanisms routinely to manage network flows, just as a DNSP is not allowed to shed load routinely. If a DNSP wishes to control a DER in this way, it should enter into an appropriate NSS contract.

Leaving it to the DNSP's discretion under the current arrangements to strike the right balance between market efficiency and safety/security of network in the connection agreements may not promote the right outcomes for the market more broadly given that DNSPs may have no incentive to consider the wider commercial and market benefits of DER. As a result, any new connection arrangements or amendments to existing policies must incorporate a market-wide consideration.

8.5.2 Future Work

Key areas for future work include:

- Development of new connection standards for DER. Connection rights, obligations and standards should ensure that all DER are able to connect to a distributor's network with minimal transaction costs and recognise the market benefits from DER.
- Development of a transparent framework for managing DER connection requests in areas where there is limited hosting capacity.
- Consideration of the role of reliability standards under a high DER scenario and, in particular, where some form of "export reliability standard" is required. This new standard would create an obligation on DNSPs to augment their networks to add hosting capacity to accommodate more DER as existing capacity becomes exhausted.
- An assessment of networks' current ability to manage an increase in DER penetration and whether to develop threshold tests to identify where DER penetration could have a material impact on distribution network security and power quality. This could help to inform regulatory assessment of expenditure proposals.

- Establishment of clear and effective operational procedures and boundaries in relation to how a DNSP may use DER (this includes a framework for governing how a DNSP would be allowed to curtail DER when necessary in order to maintain network security).

9 Network planning and investment

How a DNSP plans and invests in its network will have implications for how the values of DER is identified and compensation paid, as well as the operation of DER technologies. The current regulatory framework governing a DNSP's planning and investment functions has been subject to a number of recent amendments. It is also being considered further under a number of rule changes by the AEMC, as well as the AER guidelines for demand management incentive scheme. As a result, this section explores, at a high level only, some of the potential constraints and risks to DER in relation to network planning and investment under the current regulatory framework (including where appropriate proposed arrangements put forward under the Roadmap).

Key findings

1. The behaviours and actions of the DNSP in planning and investing in the network will have implications for the efficiency of all DER services, not only those procured by the DNSP for NSS. We have identified a number of potential constraints and risks which may need to be addressed, including:
   - The potential for bias towards capital expenditure in favour of operational expenditure
   - The over-reliance of current regulatory mechanisms, such as the RIT-D, to support efficient network investment decisions relating to DER
   - There is no current regulatory mechanism or transparent methodology which explicitly requires the calculation of the network value from DER in all situations
   - The current regulatory determination arrangements can make it difficult for DNSPs to manage the expenditure volatility of DER procured (if the price depends on when the DER asset is used for NSS)
   - A five year regulatory control period cycle may not provide the right flexibility to support the development of DER markets. Within a five year period, there may be dramatic changes in DER technologies presenting new opportunities and the need for new protection schemes which were not forecasted at the start of the regulatory period.
2. While a DNSP may need advanced network planning tools and systems to adequately manage operations under the high DER scenario, regulatory funding of such tools and systems may be uncertain under the current model. It is also not clear if a high DER scenario will make flows more variable and unpredictable which will make it difficult for the AER to evaluate such expenditure proposals. The AER would also need to assess whether investment by other parties (i.e. smart meters, battery management systems) would provide the required information for system operation as opposed to such tools or systems.
3. The framework governing DNSP planning and investment decisions, including the revenue regulation arrangements, will have a key role in supporting the development of competitive DER services. This framework has been subject to piecemeal amendments in recent years and is currently subject to a number of rule changes. Such a piecemeal approach is unlikely to be effective under a high DER scenario as it can over-complicate the arrangements and will not provide confidence to the market and in addition may fail to keep up with technology advances and emerging business models associated with DER.

9.1 Current arrangements

DNSPs are required under the NER to consider both network and non-network solutions to augmentation and/or operation of its network. A key obligation for all DNSPs is to publish annual planning reports (APR) beyond those submitted as part of their five year regulatory determination. An APR signals to the market the necessary investment in the network, including opportunities for non-network solutions moving forward. As a result, such reports may represent a critical source of information for investors in DER and DER-related products of services.

The NER obligations on DNSPs for network planning and investment were initially modified in 2012 by the AEMC in order to achieve the following objectives in support of the NEO. [68]

- *"Efficient investment in distribution networks by including incentives for DNSPs to explore non-network options as alternatives to capital expenditure and for non-network providers to efficiently plan and offer alternative, more cost effective options to network augmentations;*
- *Efficient operation of networks, for example, by ensuring DNSPs have a clearly defined and efficient planning process to allow them to identify and address potential problems on the network in a timely manner; and*
- *Efficient use of electricity services, for example, by ensuring network users have the best information available in order to be able to plan where best to connect to the network."*

The arrangements for distributors include:

- Revised distribution annual planning review requirements, including a requirement to publish an Annual Planning Report that sets out the outcomes of the annual planning review and will include information in respect of capacity and load forecasts and system limitations;
- Several demand side engagement obligations, including a requirement to develop and document a demand side engagement strategy, and in the process engage with non-network providers and consider non-network options in accordance with this strategy;
- An obligation to conduct joint planning arrangements between network businesses to address any common problems impacting on their networks; and
- A revised RIT-D which lowered the threshold to an estimated expenditure of $5.0m million from $10.0 million.

A subsequent amendment to the NER was made in 2016 to further help balance the incentives on DNSPs to make efficient decisions in relation to network expenditure, including the use of demand management options in place of network expenditure. The new Rules are intended to strengthen an existing incentive scheme relating to demand management and embedded generation connection incentives and commenced on 1 December 2016. The AER is currently consulting on the design of this new incentive scheme which was originally proposed in the Power of Choice Review.

The Rule change arose following concerns that the current regulatory framework creates a bias towards expenditure on network investment over non-network options. The possible bias arises for a number of reasons, including because distribution businesses have no financial incentive to factor in the broader market benefits from non-network options and they may have limited incentives to trial new non-network options.

[68] AEMC, National Electricity Amendment (Distribution Network Planning and Expansion Framework) Rule 2012, October 2012, page 17.

As explained in Section 1.3, the COAG Energy Council and AEC have proposed amendments to the NER in relation to how DNSPs procure and invest in DER assets. The AEMC is expected to make a draft determination on these issues by 1 September 2017.

9.2 ENA/CSIRO Roadmap

As part of the modelling commissioned by the ENA/CSIRO, the analysis found "significant changes are required to the current design and operational practices for the whole electricity because of changes to both the type and location of new generation sources."

For distribution, the impacts of high DER are substantial whereby the distribution network is required to now manage bi-directional flows – a departure from the original design of the system. These flows are anticipated to *"fluctuate significantly within relatively short time periods."*

Over the course of the assessment period, 2017 to 2027, the ENA/CSIRO propose the development of a range of advanced network planning, operation and intelligence tools and systems. These tools and systems are to provide for the safe and efficient integration of large scale renewable generation, micro-grids and DERs. Specifically, by 2019, the adoption of advanced network planning models, techniques and valuation methods are to have been established, whereby DERs are seen as credible non-network alternatives by distributors. The ENA/CSIRO recognise these will initially be in the form of standalone tools or techniques, and may include:

- Network topology mapping;
- DER hosting capacity (which is the amount of capacity on any given portion of the distribution system to accommodate additional DERs with existing and already-planned facilities);
- DER locational value analysis; and
- DER demand and supply forecasting.

In addition to tools and techniques, intelligence and control architectures and tools at the distribution level are to play a foundational role in the safe, reliable and efficient operation of a high volume of DER across the network. The ENA/CSIRO note this requires enhancements to monitoring and control architectures and functionality, providing for better identification and management of system constraints. These advanced tools and techniques are a precursor to the development and utilisation of ANO functions (and eventually a NOM by distributors).

The Roadmap proposes five major milestones that will impact on the DNSP's network planning role:

- **Milestone 1:** By 2018, the central and transformed role for the transmission system to support power system security has been defined.
- **Milestone 2:** By 2018, market based approaches for providing efficient capacity, and balancing and ancillary services have been established, including a set of fully tested options that would cater for a very low emission generation mix.
- **Milestone 3:** By 2019, an initial approach has been developed for coordinating and optimising decisions across the power system as a whole, which includes more effective interfacing between the Independent Market Operator[69] and the distribution network connection points.
- **Milestone 4:** By 2020, new tools and models have been developed to provide improved forecasting to better anticipate where environmental and system constraints could lead to system security issues.

[69] The Roadmap does not define what is meant by the term" Independent Market Operator". We have interpreted this to mean the wholesale market operator role, currently performed by AEMO.

- **Milestone 5:** By 2022, advanced protection mechanisms have been developed, trialled and validated to better address distributed energy resources' impacts and enhanced system operation and security.

9.3 Key principles for future market and regulatory design

As per our assessment framework (described in Section 3), KPMG considered the following market design and regulatory principles in relation to network planning and investment necessary in order to achieve market competitiveness and efficiency for DER-related products and services:

- Networks need to provide universal supply at a reasonable cost in accordance with their regulatory obligations.[70]
- DNSPs will select the most efficient solution, irrespective of whether it is a network or non-network solution;
- The role of the distribution network is to meet the needs of customers (customer centric) through facilitating physical electricity flows that support customer transactions;
- Networks must not impede competitive markets and therefore need to provide adequate hosting capacity where efficient; and

9.4 Potential constraints and risks

Investment in DER will primarily be driven by a consumer's desire to better manage, or control, its own energy use moving forward as opposed to investing in DER to support the operation of the distribution network. The behaviours and actions of the DNSP in planning and investing in the network will have implications for the efficiency of DER services. This includes:

- How DNSPs assess the potential for DER to be a credible alternative to network investments.
- How DNSPs plan and provide capacity to support DER related transactions.
- How DNSPs determine the appropriate value to pay DER services contracted as NSS.

Therefore, how a DNSP plans and invests in its network will have implications for the value and operation of DER technologies, despite being only one driver behind consumers' investment in DER.

We have identified a number of constraints or risks which may impact a DNSPs actions in relation to planning and investing in its network, and thereby potentially result in inefficient market outcomes. These are shown in Figure 11.

Figure 11. Network planning and investment – constraints and risks

[70] This principle is copied from the Grid Neutrality Principle 1 – Empowering the customer while maintaining access at reasonable cost (see Section 3.3.4).

Some of these issues are being considered in depth under the AEC rule change proposal for the contestability of energy services - demand response and network support. Therefore, we only briefly present these issues in this section and put forward some of our own perspectives.

9.4.1 A preference towards capital expenditure

A preference towards capital expenditure (capex) occurs where capital expenditure options are chosen inefficiently over operating expenditure (opex) options. The regulatory framework could create or contribute to a capex bias if it meant that a network business could gain more financially from spending on capex rather than opex.

A DNSP could have a preference towards capital expenditure and against operating expenditure under the current arrangements for the following reasons:

- Differences in the regulatory treatment of operational versus capital expenditure may create a preference for one type of expenditure over the other. For example, the Rules provide a greater guarantee of recovery of actual capex (as long the capex spent is less than the total regulatory allowance) rather than opex based projects where the AER could re-assess expenditure every five years.
- In addition, the AER has applied its benchmarking results only to opex and not to capex. The DNSP may perceive that this creates a potentially greater risk of expenditure cuts in relation to opex than to capex. This is because opex is more suited to benchmarking techniques and could be considered more comparable across DNSPs as opposed to capex which can be specific to drivers unique to each DNSP (i.e. asset life, geographic conditions, jurisdictional reliability standards).
- Capex allowances are subject to a financial rate of return – referred to as the WACC. This gives the business the opportunity of earning additional profits if it is able to finance its capital investments at a lower rate than the allowed WACC. This opportunity does not exist for opex. Again, this could give the businesses a preference to increase the proportion of allowed expenditure allocated to capex.
- The fact that capex is remunerated through the RAB and earns a return while opex is remunerated on a current basis, earning no such return, should not be a problem if the allowed return is equal to the cost of capital – an investor should then be indifferent to the form of remuneration. However, the incentives to achieve financing efficiencies and RAB growth are having an important influence in both business planning and delivery.
- The relative incentives for under-spending expenditure under the AER's capex and opex efficiency schemes may not be equal. The AER argued that as the sharing ratio of 30% - 70% is the same for both schemes, the incentives should be aligned. However, this is not based on the absolute value of expenditure and the corresponding impact on the DNSP profits - $1 of opex savings is different to $1 of capex savings due to how these are treated under the building block model, and the AER's incentives schemes.[71]
- The incentive schemes need to recognise that the net financial impact on DNSPs of the choice between opex and capex will depend on a range of variables and not just the sharing ratio. Such variables include the discount rate, the relative costs of the network and non-network projects, how the expenditure need has been allowed for in the current regulatory determination and the timing of payments to DER providers. These variables are likely to differ across investment choices.

[71] This can be proved mathematically. For example, a DNSP with the choice of $8m on a network asset which has already been approved in the regulatory determination or entering into a 10 year non-network contract at a cost of $1m p.a. will be approximately $3m worse off if it chooses the non-network option.

This is a complex matter, and different degrees of partiality potentially exist under different circumstances. It is not correct to make a general statement that distribution businesses will always prefer capex over opex projects. There may be situations where opex projects make more financial sense for the business if it is materially more profitable than capex without increasing risk.[72] The AEC has raised such concerns in its rule change to the AEMC.

9.4.2 Reliance on RIT-D

The RIT-D establishes the processes and criteria to be applied by DNSPs in order to identify investment options which best address the needs of the network. The RIT-D is applicable in circumstances where a network problem exists and the estimated capital cost of the most expensive potential credible option to address the identified need is more than $5 million. Certain types of projects and expenditure are currently exempt from assessment under the RIT-D, including projects initiated to address urgent and unforeseen network issues and projects related to the replacement and refurbishment of existing assets.

The RIT-D Rules set out the principles to which the test, developed by the AER, must adhere. The RIT-D Rules also include the procedural consultation requirements to be followed by DNSPs when applying the test. In summary, the RIT-D requires DNSPs to assess the costs and, where appropriate, the benefits of each credible investment option to address a specific network problem, to identify the option which maximises net market benefits (or minimises costs where the investment is required to meet reliability standards).

The RIT-D has several limitations that may mean that efficient demand side options, such as embedded generation, may not be taken up:

- RIT-D only applies where the cost of augmentation is greater than $5 million. This limits the potential pool of projects for which embedded generation could be considered as an alternative to network investment. Further, this is a fairly high threshold, and it may be the case that it is difficult to identify appropriate demand side alternatives to significant network augmentation.
- DNSPs have discretion in the way in which they calculate market benefits and therefore how it considers the potential market value of DER. NER clause 5.17.1(d) provides that a RIT-D proponent is only required to quantify market benefits where that proponent considers that:
  - any applicable market benefits may be material; or
  - the quantification of market benefits may alter the selection of the preferred option.

  Further, the AEMC clarified in its final determination on the RIT-D that, where an identified need is required to meet a reliability standard and therefore investment must occur even if there is a net cost, the quantification of market benefits would be optional.[73] The AER Guidelines on the RIT-D also provide DNSPs with significant discretion in the way that they calculate market benefits. For example, the AER considered it appropriate to give RIT-D proponents the option to consider wholesale market impacts on the basis that these are likely to be small.[74]

[72] In addition, a DSNP may tend to be risk averse in their decision making when planning and operating their network. Together with a DNSP's own transaction costs, this aversion may lead to inefficient investment decision by a DNSP in relation to possible non-network opportunities.
[73] AEMC, Rule Determination, National Electricity Amendment (Distribution Network Planning and Expansion Framework) Rule 2012, 11 October 2012, pp 81-82
[74] Wholesale market impacts could potentially occur where a demand side option to address an identified need also impacts the wholesale market. The AER considered that the majority of demand management projects would

The issue of how the current framework governing DNSP valuation of the benefits from DER services is discussed in the next section.

It would be inappropriate to rely solely on regulatory mechanisms, such as the RIT-D to ensure efficient choice between possible network and non-network options. With a current threshold of $5m, a RIT-D may therefore be effective for large projects (e.g. HV network augmentation), however when considering the potential scope of investment in which a DER may contribute to the operation of the network, and therefore present as a credible, alternative non-network solution, proceeding through a RIT-D process would be too costly and clumsy for projects of this size. Furthermore, at the current threshold level, it is unlikely that such investment in DER would even be considered in any instance by a DNSP as part of the RIT-D process.

9.4.3 Valuing of DER services

For customers with DER to receive the appropriate remuneration for any network value generated, there needs to be a financial payment from the DNSP to the customer. This could be through an explicit financial transaction and/or implicitly through the design of network tariffs. For example, a DER customer could be rewarded through lower electricity bills caused by the reduction in its network charge resulting from its lower consumption compared to the customers who do not have DER. The size of that reward depends on the design of network tariffs, in particular the percentage of the network costs which is allocated to fixed versus consumption tariffs. A higher relative proportion of consumption tariffs compared to fixed daily charges will provide more savings to customers.

There is no current regulatory mechanism which explicitly requires the calculation of network value from DER in all situations. This could create two barriers to remunerating DER for any network value provided.

Firstly, this makes it more difficult for DNSPs to transparently reflect the network value in their planning and investment decision making. Secondly, it could impede the ability of DER proponents to develop credible proposals to offer DNSPs as they are unsure how the DNSP will assess and pay for the value. Instead, the DER proponent will have to rely on other sources of information such as the RIT-D and Distribution Annual Planning Report (DAPR) to obtain an understanding of how the DNSP will consider and calculate potential network value.

9.4.4 Interaction with revenue regulatory framework

How DNSPs' expenditure is approved and treated under the economic regulatory framework under Chapter 6 of the NER will clearly influence planning and investment decisions. This section discusses at a very high level a potential number of interactions which could have impeded the competitiveness and efficiency of a market for DER.

Regulatory funding of advanced tools or systems may be uncertain

While a DNSP may require use of advanced planning tools or systems in order to adequately manage its network under a scenario of high DER penetration, regulatory funding of such tools or systems may be uncertain moving forward given the potential difficulties for the AER to assess their need and use. For example, it may be plausible that a high DER scenario will make energy flows across the network more variable and unpredictable; this is unlikely to be uniform (both in time and magnitude) across all distribution networks.

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be too small to have a material impact on the wholesale market, and therefore left it to the discretion of the RIT-D proponent to assess these.

In addition, as discussed in Section 7.4.1, it is not clear whether a high deployment of DER will automatically make network flows unpredictable and therefore distribution system operation more uncertain and volatile. DER will likely make customers more responsive which could remove some of the operational need for active control by the distributor and, in addition, with the high level of automation to DER technology, forecasting flows and customer behaviour should become more predictable.

This uncertainty is likely to be exacerbated as differing technologies come to market, with varying operating profiles. Such factors will make it difficult for the AER to evaluate each DNSP's expenditure proposal – and specifically the need for network and non-network solutions moving forward. An aspect that the regulator will also consider is the relationship between the rationale for ANO and the installation of smart meters by DER customers. The AER might consider whether the information provided by smart meters could be sufficient for network planning and operations.

Managing expenditure volatility associated with DER procurement

Under current arrangements, network investment plans are assessed by the AER every five years, with allowed expenditure levels being set for the next five years. This works to incentivise a business to seek cost savings, since it is able to retain a proportion of any savings on the allowed expenditure. However, a business is also exposed to potential losses if it over-spends its allowed expenditure. The level of certainty that the business has in the allowed expenditure level to cover its true costs will influence its investment decisions.

The cost profile of a DER solution can differ significantly compared with capital infrastructure. With capital infrastructure, most of the costs are upfront and a business manages the expenditure risk during the construction phase. However, for certain types of non-network projects, the cost profile can be quite varied over a five-year period, particularly if the use of DER is dependent on network and weather conditions. As a result, the costs associated with procuring DER may be difficult to forecast.

Under some mechanisms, such as avoided transmission use of system (TUOS), the DNSP is allowed to pass through annual amounts in their approved prices, and hence the volatility is reflected in the customer prices. However under the current framework, generally the DNSP is then exposed to the volatility in actual costs over the regulatory period. Therefore, requiring the distribution businesses to manage the expenditure risk associated with procuring DER could put these projects at a comparative disadvantage compared with capital infrastructure projects.

There is a general related point as to whether the current five year regulatory control period cycle will provide the right flexibility to support the development of DER markets. Within a five year period, there may be dramatic changes in DER technologies presenting new opportunities and the need for new protection schemes which were not forecasted at the start of the regulatory period. The five-year regulatory period may limit the extent to which DNSPs can comfortably enter into long term contracts for network support services. This is a small risk but could undermine certainty of returns over the life of the asset.

Incentive to invest to support DER commercial transactions

A question arises as to why a DNSP would pay for the costs of network upgrades, or procure NSS, to deal with export constraints when it can simply deny connection, or limit access, at no cost to itself. Indeed, revenue regulation encourages a DNSP to choose this less costly alternative. The issue is that, unlike with imports, there is no reliability standard that mandates the level of access that must be provided for exports. The issue of export reliability standards is discussed further in Section 8.

9.5 Advice and future work

9.5.1 Advice

As noted above, we have discussed the potential constraints and risks at a high level given that the issues of network planning and investment are the subject of a number of rule change proceedings under consideration by the AEMC, as well as the AER guidelines for demand management incentive schemes. Despite our high level commentary, we recognise the need for further consideration of how the current arrangements (and proposed changes) address the following:

- The definition and ability for DER to be used as a firm alternative to network assets. This may assist in avoiding any potential preference a DNSP may otherwise have for pursing capital expenditure projects. Specifically, this may assist in mitigating any risk that a DNSP could over-specify the terms and conditions needed to achieve "firmness".
- How future expenditure proposals are to be assessed in light of the need for advanced tools or systems. In order to assist the AER in reviewing future "smart grid expenditure proposals" for such tools or systems, the AEMC and AEMO (and the ENA) may wish to consider developing a threshold test for high penetration of DER for different network topologies in each jurisdiction in terms of its effects on distribution network security and power quality. A similar approach has been proposed by De Martini[75] which provides some objective criteria for defining Stage 2 moderate to high level DER adoption threshold.

  - *DER adoption reaches beyond about 5% of distribution grid peak loading system-wide.*[76]
  - *Installed DER capacity interconnected to the PG&E distribution grid is about 8% of peak load system-wide with the following adoption pattern:*
    - *1% of all feeders may have DER capacity levels at or near 100% of the feeder peak load;*
    - *3%of all feeders may have DER capacity levels exceeding 30% of the feeder peak; and*
    - *8% of all feeders may have DER capacity levels greater than 15% of the feeder peak.*

The framework governing DNSP planning and investment decisions, including the revenue regulation arrangements, will have a key role in supporting the development of competitive DER services. This framework has been subject to piecemeal amendments in recent years and is currently subject to a number of rule changes. Such a piecemeal approach is unlikely to be effective under a high DER scenario as it can over-complicate the arrangements and will not provide confidence to the market and it may fail to keep up with technology advances and emerging business models associated with DER.

9.5.2 Future work

Key areas for future work include:

- Developing a definition and ability for DER to be used as a firm alternative to network assets. This may assist in avoiding any potential preference a DNSP may otherwise have for pursing capital expenditure projects. Specifically, this may assist in mitigating any risk that a DNSP could over-specify the terms and conditions needed to achieve "firmness"

[75] Lawrence Berkeley National Laboratory, De Martini & Kristov, *Distribution Systems in a High DER Future: Planning, Market Design, Operations and Oversight*, October 2015.
[76] This level of adoption typically results in pockets of high customer adoption in some neighbourhoods and commercial districts, which creates the need for enhanced functionality inherent in Stage 2.

- Consideration of the role of reliability standards under a high DER scenario and particularly where some form of "export reliability standard" is required. This new standard would create an obligation on a DNSP to augment their networks to add hosting capacity to accommodate more DER as existing capacity becomes exhausted.
- An assessment of network's current ability to manage to increase DER penetration and whether to develop threshold tests to identify where DER penetration could have a material impact on distribution network security and power quality. This could help to inform regulatory assessment of expenditure proposals.

10 Non-distribution elements

This report has so far focused on the relationship between a distributor and the development of competitive DER markets. There are several other elements which warrant further consideration in ensuring a competitive and efficient market for DER products and services. These non-distribution elements are a reflection of the broader market arrangements, as well as the emergence of new business models and the continued penetration and advancement of DER and supporting (e.g. metering) technologies. While these issues are not relevant to the role of DNSPs, the AEC has also asked us to consider at a high level the potential interactions of these elements.

Key findings

1. Access to the wholesale energy market and peer-to-peer trading may represent the most likely sources of value for DER assets outside of any direct interaction between a consumer and a distributor.
2. Digital meters will be included in the installation of DER technologies and offer a useful means for measuring their performance, maximising the ability of the DER to capture its full value to the market, and may support trading and settlement of some DER products. The introduction of competition in the market for metering services, in addition to the regulatory requirement for digital meters to be introduced more broadly, will assist in this process.

   Consistent with current arrangements, retailers / aggregators or other third parties should be financially responsible for trading the output of DER in the wholesale market. Where restrictions are placed on this use of DER, these restrictive policies must be transparent to consumers, retailers and aggregators.
3. Other considerations with respect to peer-to-peer transactions will be product definition in addition to the trading and settlement rules for such transactions. These will foster confidence and liquidity through enforceable contractual terms and conditions. We would expect that each platform will develop their own rules and those with the most attractive rules/parameters will gain market share. The market in such commercial platforms should be allowed to develop without regulatory intervention.

This chapter does not represent an exhaustive review of all non-distribution elements and instead provides for initial consideration only of the potential impacts of a DER market on several key elements, including:

- Access to wholesale energy market; and
- Peer-to-peer trading.

We consider that these two elements may represent the sources of value for DER assets outside of any direct interaction between a consumer and a distributor. This would be in addition to the value the customer enjoys from increased self-consumption and energy independence.

It would be expected that these two elements will be front of mind for policy makers, regulators and market participants alike as the market transforms and new opportunities are created. It should be noted that several of these elements have been broadly considered, directly and indirectly, as part of various rule changes or market reviews completed by the AEMC in recent years.[77] However, such assessment have typically focused on the issues challenging the NEO as of today. Consistent with our analysis, we have considered these arrangements from a future period of time, 10–15 years from today, allowing for broader consideration of the potential issues arising from a DER market and the potential market responses to those issues.

10.1 Current arrangements

Access to the wholesale market is currently restricted to the minimum thresholds of 5MW and 30MW for generation and loads. The NER do not specifically preclude the use of DER by retailers/aggregators in offering services in the wholesale energy market, however it is unlikely that the scale of most DER was front of mind in drafting the Rules. A retailer/aggregator may therefore proceed with the provision of aggregation services consistent with the requirements of a Market Small Generation Aggregator (MSGA). A MSGA will require access to advanced smart meters at all customer locations – it is likely this may be cost prohibitive for some at present. Further, such advanced meters have not been widely rolled out across the NEM (excluding Victoria). Similarly, a customer who contracts their DER with an aggregator may be required to interact with multiple Financially Responsible Market Participant (FRMP). Under the NER, this will require the consumer to have multiple connection points at their premise which currently is restricted.

With peer-to-peer trading, several regulatory barriers exist in the NEM to the development of such platforms including, but not limited to, a requirement to be the FRMP in order to transact at a specific connection point, as well as an inability to establish net metering arrangements at more than one premise. Similarly, the NER places limitations on how users of the network may be charged (e.g. restrictions for exporting to the grid) and the ability to engage / transact directly with peers.

However, these are financial barriers for a trading arrangement which is simply a financial contract by a customer to purchase energy from a particular generator (usually renewable generator)[78]. Similar to the financial contracts in the wholesale market, it does not form part of the least cost dispatch process administered by the AEMO and has no direct impact on power system security.

10.2 Access to the wholesale energy market

While the size of any one DER will preclude a consumer from participating in the wholesale energy market, the role of a retailer, aggregator or other third party (collectively referred to herein as "aggregator") may present an opportunity for them to participate on behalf of a consumer instead. In this instance, the aggregator would combine multiple DER assets to form a portfolio, and sell the products or services derived from that portfolio into the wholesale energy market (e.g. capturing high spot prices), directly to network businesses (e.g. in the form of NSS) or, where possible, as an ancillary service to AEMO. The products and services, and therefore value, of any one portfolio would be subject

[77] For example, the AEMC rule change review titled *Multiple Trading Relationships* assessed the current framework to be sufficient in enabling customers to set up multiple trading relationship arrangements. Such arrangements included the establishment of Community Energy Programs (a form of peer-to-peer trading).
[78] Peer-to-peer trades recall the physical contract paths that were developed in the US power pools during the 20^{th} century. These contracts affected the dispatch process. Since then, most US wholesale markets ignore financial contracts and dispatch on a least cost basis with nodal pricing.

to the individual technologies captured and the ability for the aggregator to collectively control those assets.

Importantly, the ability for an aggregator to combine multiple DER assets will be subject to whether:

- ***The aggregator is able to offer a better price for the customer's exported generation than the existing retailer's feed-in-tariff (FIT) scheme.***

  A key factor in the emergence of the aggregator services is whether the aggregator is able to offer a better rate for export of generation than a retailer's feed-in-tariff rate. Participation in the NEM will likely require the customer to forego this contract. This would depend upon whether the customer is receiving a premium rate or the voluntary (unsubsidised) rate offered by retailers.[79] While these premium FIT schemes are now closed for new entrants, existing customers have been grandfathered and will continue to receive the premium rate. An aggregator would only be able to capture such customers if the aggregator is able to access the funding for the premium rate. However, it is not clear if this is allowed under the existing arrangements.

- ***The customer is comfortable with having multiple service providers at its premises.***

  In order to trade with a second FRMP acting as an aggregator, the customer would be required to establish a second connection point at its premise. The AEMC recently reviewed this arrangement as part of its consideration of multiple trading relationships and chose not to amend the NER. The AEMC, in handing down its final decision, noted:

  "The need for a new framework is limited as customers can already engage multiple retailers at a premises under the current rules, and other market reforms can provide similar benefits to customers without additional costs. Implementing the rule change request is unlikely to deliver material benefits for most customers but is likely to impose significant costs on retailers and distributors, which may result in increased electricity retail prices for all customers.[80]

  It is also possible that the consumer's existing retailer may act as an aggregator on the consumer's behalf for the purposes of participating in the wholesale energy market. This would be subject to the contract being struck between the consumer and its retailer and any existing arrangements they had entered into.

- ***The licencing and regulatory requirements on the aggregator.***

  The existing licensing and regulatory requirements do not explicitly preclude the use of DER by an aggregator for the purposes of participating in the wholesale energy market. However, it is likely in making the rule change that the AEMC did not anticipate potential aggregation of DER assets at such a scale. In order to meet the minimum thresholds (5 MW and 30 MW) for active participation in the wholesale energy market, an aggregator will likely require access to a large volume of DER assets.

  Additionally, those individual assets must be accompanied by access to an interval meter at each location.

[79] FIT schemes generally fall into two categories: premium schemes, which provide a tariff payment that is significantly greater than the wholesale cost of electricity, and non-premium schemes, which generally provide a tariff payment that is equivalent to the avoided cost of supply due to the operation of a rooftop solar generator.
[80] Australian Energy Market Commission. Final Rule Determination: Information Sheet - Multiple Trading Relationships. 25 February 2016

10.3 Peer-to-peer trading

The growth of peer-to-peer services is having a transformative effect in other sectors, such as hospitality, transport and lending, and is being widely spoken about, and in certain instances trialled, in energy markets in Australia and around the world.

Two such examples include the UK Piclo model and the Netherlands Vandebron model. Both of these models focus on connecting generators directly with consumers. A third such model, currently on trial in Western Australia by Power Ledger, seeks to utilise surplus renewable energy generated from residential or commercial DER, by providing producers and consumers a trading and market clearing platform.[81] This model takes advantage of Blockchain technology creating a transparent, auditable and automated platform for all participants.[82]

A peer-to-peer service has the potential to raise considerable new challenges for regulators and policy makers, particularly, where multiple services (platforms) are established across the NEM targeting specific technologies or participants. Such are the unknowns associated with the future advances in both DER and supporting technologies (including platforms), and consumer preferences for managing their energy supply.

It is possible these services provide nothing more than a "netting" arrangement for a consumer's physical and/or financial position taking into consideration their existing retail contract and DER asset(s), with limited or zero impacts beyond those already forecast to the actual operation of the electricity system. However, it is similarly possible that such platforms may negatively impact the roll out of existing market participants, such as retailers where consumers have sufficient DER capability to "self-supply". Further, the emergence of such trading arrangements may lead to more general, inefficiency in market outcomes associated with the use of DER. For example, where the value associated with DER products or services is not maximised via the peer-to-peer trading platform alone or where participation in one market adversely limits the participation in another market (e.g. selling energy in one market limits the ability to sell NSS in another).

Finally, subject to the form of platform facilitating peer-to-peer trading, there may be a reliance on the operation of the regulated network. Where such reliance is placed, it may be argued that the platform must therefore be subject to the NEM requirements, and in doing so the requirements of the NEL and NER. Under the existing framework governing the NEM, there are various regulatory barriers limiting peer-to-peer transactions in the market. These barriers include, but are not limited to, a requirement to be the FRMP in order to transact at a specific connection point, as well as an inability to establish net metering arrangements at more than one premise. Further, as discussed in Section 6.4, the current NER places limitations on how users of the network may be charged.

In establishing a peer-to-peer trading platform, one that relies on use of the regulated network, these barriers would need to be appropriately addressed in order to facilitate participation in the market. Other platforms, such as one facilitating financial trading of a consumer's energy position only, would not require similar changes to the governing framework for the sector. However, it may have ongoing implications for the operation of the DER assets in the broader market – for example whereby a financial position taken by an asset owner impedes the use of a DER asset to fulfil a role in helping to manage the network for fear of financial loss.

A peer-to-peer trading platform in any sense raises a unique question in how each individual electricity transaction is to be validated. In general, electricity transactions raise complexity issues given the

[81] Power Ledger. Website <https://powerledger.io/> Last accessed 17 March 2017.
[82] Ibid.

inability to identify the source of electricity. Where energy is sold from one DER owner to a consumer, it is impossible to accurately account for the amount of energy without sufficient metering at the customer's premise in order to measure the imports from and exports into the network.

Other considerations with respect to peer-to-peer transactions will be product definition in addition to the trading and settlement rules for such transactions. These will foster confidence and liquidity through enforceable contractual terms and conditions. We would expect that each platform will develop their own rules and those with the most attractive rules/parameters will gain market share. The market in such commercial platforms should be allowed to develop without regulatory intervention.

10.4 Key principles for future market and regulatory design

The two alternative sources of value for DER described above may present some challenges for policy makers and regulators in how they govern the operation and participation in the wider energy supply system. These challenges are exacerbated where the future uptake of the DER is unknown and the potential development of new technologies or platforms remains unclear. However, the development of such platforms and the participation of DER in new (or existing) markets may be guided by key principles for market design. In certain instances, these principles are consistent with those discussed in prior chapters and include:

- Retailers, aggregators and other third parties should be provided access to the wholesale energy market where sufficient scale of DER is achieved.[83]
- Decisions with respect to how DER is utilised across markets (wholesale, DEM/NSS or other) is with the owner of DER or third party (where contracted).
- New platforms established facilitating the trading of DER, such as those enabling peer-to-peer transactions, must be neutral in relation to providing access to participants and specifically the form of technology which may underpin future transactions.[84]
- The information exchanged between markets must therefore be done transparently - this will further assist in the trading and settlement of positions taken by individual consumers, retailers, aggregators or other third parties.

10.5 Advice

Digital meters often partner the installation of other DER technologies, offer a useful means for measuring their performance and may be necessary for trading and settlement of some products. The introduction of competition in the market for metering services, and a requirement for interval meters to be introduced more broadly, will assist in this process.

Consistent with current arrangements, retailers/aggregators or other third parties should be financially responsible for trading the output of DER in the wholesale market. Where restrictions are placed on the use of DER, these restrictive policies must be transparent to consumers, retailers and aggregators.

[83] Existing, known barriers to participation, such as the requirement for a second connection point and installation of an interval meter at a customer's premise may require review as the total volume of DER increases providing greater opportunities to participate in new/existing markets moving forward.
[84] Failing to do so may create an investment bias for any one technology leading to potentially inefficient market outcomes – particularly where certain technologies do not meet the requirements of the market more broadly.

As recommended in this report, there is a need to develop the regulatory and market arrangements to facilitate peer-to-peer transactions. This is likely to require considering how the costs of the electricity supply chain, including government scheme costs, are levied on such transactions in addition to issues relating to customer protection and settlement. For example, whether such transactions should be exempt from paying transmission charges or retailer obligations (renewable energy or energy efficiency certificates, for example). In addition, further consideration is required as to the minimum requirements of a DER and consumers, in order to participate as part of an aggregator arrangement or peer-to-peer trading platform.

11 Way forward

This chapter presents a summary of our findings regarding potential constraints and risks to the development of efficient and competitive markets for DER products and services and the suggested way forward to address them.

11.1 Summary of findings

The Roadmap represents both a substantive piece of work and a very useful contribution to the debate on how best to maximise the opportunities created by investment in DER across individual networks. However, the current arrangements (including some of the proposed Roadmap amendments) could create a number of potential constraints and risks that would not be conducive to the development of a competitive and efficient market for DER-related products and services. A large portion of the issues arise as a result of the direct and indirect interactions between distributors and DER owners. These risks are potentially compounded under a scenario whereby multiple commercial trading platforms for DER products and services are established outside of the operation of a DSO.

Table 6 below summarises those risks and issues identified as part of our assessment.

The behaviour of a DNSP towards DER, and markets for DER-related products and services, will depend on its perception of the impacts to its own financial position and its future roles under a high DER penetration scenario. This behaviour will depend on the regulatory framework governing its operations. Changes to this framework in the short term are likely to be imperfect and could ignore the possibility that distributors may change their current operational practices and develop new risk management techniques in response to the emerging technologies. Pre-empting the development of a market for the DER and jumping instead to the development of new, or amending existing, regulations therefore has the capacity to limit the organic growth of competitive markets for such products and services, in particular, where these markets are developed outside of the existing energy supply market.

Further, consideration of the materiality of those identified constraints and risks will vary over the different stages of market development and the level of DER deployment. Where multiple commercial trading platforms for DER services are established and/or where third party service providers such as retailers or aggregators seek to access wholesale energy markets, the participation of DER in more than one market may lead to issues of co-optimisation. This will depend on how the DNSP interacts with such commercial platforms and importantly the transparency of those platforms and information exchanges established.

Table 6. Potential constraints and risks

Element assessed	Constraints and risks
Procurement of NSS •	1) Direct procurement from customers creates risks and issues for both the owner of DER and also to market efficiency. The materiality of these risks will vary over the different stages of market development and the level of DER deployment: a) There is potential for a DNSP to under-pay the DER owner the associated network value. This is a reflection of the DNSP being the single buyer of network support services and is complemented by the cost minimisation incentives under the economic regulatory framework. The current lack of transparency on the potential network value from DER adds to this risk. By contrast, the competitive dynamic inherent in the energy market should drive up the value offered to customers. b) The prospect of DNSPs directly procuring network support services from the DER owner creates issues of enforcement and compliance, as this may require a means to financially penalise the DER owner if it fails to comply – hence, in the absence of being able to impose a financial penalty, automatic control is required. However, having the direct means of control could prevent the DER from accessing other revenue from competitive DER-related products. Retailers or other intermediaries might create more flexible risk management options in this context. c) Some consumers may not have the means and ability to fully understand and evaluate any offer from the DNSP for network support. Therefore, there is a risk that consumers will not make an informed choice. While this may be an issue to all forms of DER procurement, there may be additional confusion from a DNSP attempting to procure directly from customers given existing relationships. d) To procure directly from customers will require the DNSP to develop its own products and solutions in order to offer to customers (such as the existing load control products). This could create a further barrier to other competitive products if the DNSP is inclined to look more favourably on the products it has developed (and less favourably on products developed within the competitive market, such as those developed by retailers or other third parties). A DNSP will always have a greater understanding of what its own products can offer and the associated risks, and is able to design those products to match its own preferences. Nevertheless, DNSPs should be encouraged to utilise the most efficient source of DER, whether it is sourced in-house or from customers or via third parties. 2) It is not clear if DNSP procurement will provide long-term certainty for DER owners over the investment life under the current economic regulatory framework. However, this may not be an issue given that a considerable amount of DER investment may be driven by personal circumstances (e.g. better management of electricity bills). 3) A reliance on procurement could delay network tariff reform as it places less pressure on facilitating customer response through tariffs. Such inter-dependencies between these components need to be recognised.
Co-optimisation between markets •	1) Co-optimisation will be an issue for both interaction with the current wholesale market and also across any distribution-level energy markets. 2) For a DNSP to establish a market for the procurement of network support services creates questions as to how this market should interact with other commercial platforms for DER services as well as whether the establishment will impact on the commercial viability of such platforms. 3) Under a high DER scenario, there could be a need to coordinate the deployment of DER across multiple markets. In delivering NSS, a DER will generate, or consume, energy at times that are of most value to the distribution network. In delivering energy, on the other hand, the DER will operate based on the value to the wholesale energy market. Whilst these times might coincide, often they will not. For example, high wholesale energy prices may lead to export constraints in the distribution network, a DER would need to increase output to deliver energy but decrease output

Element assessed	Constraints and risks
	to deliver NSS. Obviously, it cannot do both. Further consideration is needed on this matter. There is a risk that co-optimisation will not be properly considered at market start and therefore may become a difficult issue for attempting to retro-fit the appropriate arrangements. 4) It is important for the framework going forward not to create any preference or incentives for the DNSP to favour its own market platform over other platforms. If a commercial platform is effective at marketing and co-optimising the multiple DER-provided services, this should lower the price of NSS and encourage the DNSP to use it. However, for a DNSP to use commercial platforms for the procurement of NSS, a degree of trust in the ability of such platforms to deliver will be required, especially in the early stages of development. DNSPs are likely to have an understandable preference for their own products and solutions. In addition, there could be a considerable first mover advantage to establish a market for DER related products or services before any commercial platforms emerge. Against this context, we envisage that it will be very difficult for the regulator to fully assess DNSP expenditure proposals to fund investment in such a market under the current Rules.
Network tariff setting •	There are limitations with the current pricing principles that will impede the development of DER and in addition that, to date, there has been a lack of consideration of the appropriate tariff structures for DER transactions. 1) DNSP proposed demand tariffs are not totally reflective of network value as they are based on non-coincident peak and are not locational specific. Since it is coincident demand that drives network augmentation costs, such tariffs are only cost-reflective to the extent that the coincident and non-coincident maximum demands happen to occur at the same time. For residential customers, this is the exception rather than the rule. 2) A key question is whether DER resources should be exposed to residual network charges compared to the charges incurred by large scale generation. If residual charges continue to be charged on a fixed basis, customers with low usage will – at some point – find it worthwhile disconnecting from the grid, and increasingly the grid will be de-populated as the residual charge increases. The Roadmap recognises this risk, from fixed charges, and proposes a discounted tariff for those liable to disconnect from the grid. This is an important start and more analysis is needed considering how best to structure residual charges to all customers. 3) Constraints with current Rules could prevent different network tariffs' designs from being considered (for example, prohibition on export tariffs under NER clause 6.1.4). 4) There is a need to consider the cost reflective tariff for peer-to-peer transactions and whether such transactions should bear a share of the transmission network costs. 5) The prospect of asset stranding could discourage DNSPs from appropriate tariff reform. The materiality of this issue may increase under high DER. The five year lag between tariff structure statements creates a material risk that tariff reforms will fail to keep pace with market developments. In addition, uncertainty about network tariff reform is likely to impede DER market development. DNSPs may over time become less encouraged to design tariffs to correctly address network peak demand growth, if they believe they can manage this through direct NSS agreements with consumers or through capital investment. This will weaken the signal for DER. Therefore in the absence of further reform, network tariff development may create barriers to the efficient development of DER.

Element assessed	Constraints and risks
Distribution system operation •	1) Potentially, a considerable amount of transactions could occur under existing network capacity without any risks to operation. a) This potentially includes aggregated DER in wholesale, not only peer-to-peer transactions. Constraints would only occur where reverse flows are sufficient to affect voltage control or where flows approach capacity of network assets. b) Therefore, it is not clear if increased DER penetration will require such infrastructure – customer behaviour may become simple to forecast due to use of IT controls. This potential creates difficulty for the regulator to approve infrastructure investment as proposed by DNSP.[85] However, we note that DNSPs could invest in such systems without any approval as revenue determination provides discretion. Hence, DNSPs could start to become more active DSOs themselves. 2) If distribution system operation becomes more complex and uncertain under a high DER scenario, there could be potential conflicts and inefficiencies if DSO and DNO roles remain integrated within DNSPs' regulated businesses. These are: a) As part of its core regulated business, a DNSP may own and operate its own DER. For example, "controlled load" is essentially a DER technology, providing NSS to the DSO. Associated assets will be included in the DNSP's regulated asset base. Thus, a DNSP can earn a guaranteed regulated return on such DER, whereas DER that is developed and owned by consumers or other parties does not have such a guarantee. This may create a barrier to these competitive alternatives emerging. b) A DSO must choose between its own products (i.e. network options provided by the DNO) and products developed and offered by third parties (i.e. non-network options). There may be cultural, psychological and commercial reasons why a DSO will be biased towards choosing its own products. Indeed, the ANO tools might be developed (possibly inadvertently) in a way that creates such a bias. c) Revenue regulation treats network options as capex and non-network options as opex. Therefore, any asymmetry between capex and opex incentives will give rise to corresponding biases between network and non-network options. d) The DNO, in developing its own products, is likely to have much more relevant information (because this is internal to the DNSP business) than third-party NSS developers (who must rely on information published by the DNSP). This can contribute to a lack of market transparency and information asymmetry where there is close integration between the developer of a NSS product and the procurer. e) With the large sunk costs of the DNO, DNSP management is likely to focus on the associated risks, e.g. around stranded assets. At best, this is a distraction from its DSO role; at worst, it could create conflicts for the DNSP between acting in the consumer's interest and acting in the interests of its DNO role.
Access and Connection •	1) DER technologies, such as solar PV and batteries, have different technical characteristics to load and different impacts on the safety and quality of distribution. Therefore, rights and obligations around connecting these technologies behind the meter may likely need to differ from conventional load connections (e.g. a new air-conditioner). However, these rights and obligations are yet to be fully developed, creating uncertainty for the DNSP and consumers.

[85] Regulatory expenditure on protection systems creates a material risk for customers as they could be required to pay for infrastructure they do not need or (importantly)where they have not been given the opportunity to change their behaviour to avoid the need for the protection systems (i.e. through network tariffs).

Element assessed	Constraints and risks
	2) Reliability standards apply to conventional distribution service, supplying consumer load. There are no corresponding export reliability standards for the new "export" distribution service of accepting consumer exports onto the grid for delivery to HV or the transmission network. Thus, an exporting-consumer's "access" to the network is uncertain. 3) Correspondingly, DSOs have "load shedding" systems to curtail conventional distribution service when the network would otherwise be overloaded or insecure. However, there are no corresponding systems to curtail exports when needed. Thus, DSOs need to be more conservative in allowing generating devices to connect. If DSOs were to obtain "generation-shedding" capabilities (e.g. through remotely-controllable inverters), policies and procedures need to be developed around how these are controlled. 4) Where connection of new generating equipment must be limited for the above reasons, there needs to be some transparency around how, when and where that might occur. For example, the publication of "hosting capacity" information indicates where constraints are approaching.
Network planning and investment •	1) Potential limitations within the current regulatory framework could impede efficient outcomes (some of which have been raised earlier in this table) a) Cultural barriers – risk averse and transaction costs could prevent efficient choice b) Any asymmetry between capex and opex incentives will give rise to corresponding biases between network and non-network options c) Regulatory constraints (i.e. five year regulatory period) d) Reliability Standards leading to overly restrictive control terms and conditions for DER e) DER costs uncertain as it is dependent on when/frequency of DER need but DNSP exposure to any over-expenditure above allowance. 2) Currently, there is reliance on regulatory mechanisms (particularly the RIT-D) to ensure efficient choice of a preferred option: specifically, in choosing between network and non-network options. A RIT-D may be effective for large projects (e.g. HV network augmentation) but too costly and clumsy for smaller projects (e.g. around MV or LV network). Regulations are slow to change (e.g. because of five-year regulatory periods) and may not keep up with DER technological change. 3) While a DNSP may need advanced network planning tools and systems to adequately manage operations under the high DER scenario, regulatory funding of such tools or systems may be uncertain under the current model. It is also not clear if a high DER scenario will make flows more variable and unpredictable. It could be difficult for the AER to evaluate such expenditure proposals.

11.2 Potential Alternative Approaches

Given the risks identified above, we advise that there is a need to reform the arrangements governing the nature of the DNSP interactions with DER to ensure that the DNSP exercise its functions consistent with the long term interests of customers. This report raises the following as potential alternative approaches[86]:

- Place increased regulatory monitoring and information disclosures on DNSPs' behaviour;
- Place restrictions on the DNSP regarding how it procures DER for network support, e.g. restriction on direct procurement from customers;
- Reform the role of the DNSP such as structural separation of the DSO and DNO roles and responsibilities; and
- Change the economic regulatory framework governing DNSPs, for example reforming the legislated reliability standards.

This report does not make any recommendations on alternative approaches. There is a considerable amount of uncertainty regarding potential development of DER, and the materiality of these constraints and risks will vary over the different stages of market development and the level of DER deployment. These risks are compounded under a scenario where multiple competitive market platforms for DER services are established as this bring issues of co-optimisation to the front.

In addition, our analysis of the materiality of these risks depends on understanding distributor behaviour in the future under a high DER scenario. This is likely not be to perfect and could ignore the possibility that a DNSP may change their current operational practices and develop new ways to manage risks associated with emerging technologies.

For these reasons, we do not consider it prudent to make firm recommendations in the absence of further analysis and discussion. Rather, we would like to make the following comments.

To date, the economic regulatory framework has attempted to resolve any perception of DNSP bias to its own products (and capex) through piecemeal additions to the Rules, mainly in the area of information disclosure. Such an approach is unlikely to be effective under a high DER scenario as it can over-complicate the arrangements and will not provide confidence to the market. In addition, greater information disclosure by itself will not be sufficient. There will also be a need to establish clear principles on outcomes consistent with the NEO and to monitor outcomes and DNSP decisions against those principles.

Therefore, a key risk is the pressure placed on the role of regulatory frameworks and the regulator to ensure that the outcomes best promote customer interests. Given the uncertainty and complexity associated with DER, the regulator will be put in the difficult position of making an expenditure assessment of DER-related technology and managing potential conflict of interests between DNSPs' active involvement in DER and system operation.

We consider that there will be a need for increased regulation and transparency to align the behaviour of network businesses to the wider market efficiency as well as that there is no preference or incentives for the DNSP to favour its own DER products or its own market platform over other providers. The nature of the five yearly regulatory periods may also impede flexibility and innovation in this area.

[86] Under the assumption that tariff reform will not adequately resolve the risks.

Given the risks and costs of regulation, we advise that there is a need to consider how best to promote the development of competitive providers of DER services. Competition and non-discriminatory access where practicable, are the best mechanisms for providing services to customers at an efficient cost.

Fostering the development of competitive third party providers and competitive platforms could be a better alternative than trying to regulate outcomes under DNSP procurement models. The development of the arrangements for DER should be driven by consumer choice and preferences and the role of market design and regulatory frameworks is to align individual decisions with the long-term interests of consumers more generally.

11.3 Way forward

To process the issues identified in this report, we recommend that the Council follows two courses of action:

1. Facilitate industry agreement to a detailed list of principles for DER which best promote the interest of customers; and
2. Implement a work program to address the potential constraints and risks which will influence the development of DER services not covered in the Roadmap.

11.3.1 Principles for future market and regulatory design

This report assesses the ability of the current regulatory framework (and suggested arrangements under the Roadmap) to promote the efficient use of DER and the development of competitive markets against a set of detailed principles. These principles are an attempt to provide more guidance on the desired outcomes and market characteristics consistent with maximising the efficiency of DER to the market. In developing these principles, we have built on the framework used by the AEMC (and ENA/CSIRO) and included the principles of grid neutrality developed in the US.

These principles have been developed to promote the context of achieving the NEO. We see sufficient merit in facilitating industry agreement to a set of principles needed for market and regulatory design under the future scenario of high DER deployment. Such principles can be used as a blueprint to consider policy options and would provide greater confidence to the market and investors. The principles proposed in this report could be used as a starting point for this process.

11.3.2 Future work

The table below presents the future areas for work mapped to each of the six elements. Some tasks will address more than one element.

Table 7. Future work by Element

No.	Future work	Elements
1	Establish clear and effective operational procedures and boundaries in relation to how a DNSP may use DER (this includes a framework for governing how a DNSP would be allowed to curtail DER when necessary to maintain network security).	Procurement of NSS Co-optimisation across multiple markets Distribution System Operations Access and connection
2	Develop the regulatory and market arrangements to facilitate peer-to-peer transactions. This is likely to require considering how the costs across the electricity supply chain, including government scheme costs, are levied on such transactions in addition to issues relating to customer protection and	Co-optimisation across multiple markets Network tariffs

No.	Future work	Elements
	settlement. For example, whether such transactions should be exempt from paying transmission charges or retailer obligations (renewable energy or energy efficiency certificates, for example).	
3	Develop new connection standards for DER. Connection rights, obligations and standards should ensure that all DER are able to connect to a distributor's network with minimal transaction costs and recognise the market benefits from DER.	Access and connection
4	Develop a transparent framework for managing DER connection requests in areas where there is limited hosting capacity.	Access and connection
5	Develop a definition and ability for DER to be used as a firm alternative to network assets. This may help in avoiding any potential preference a DNSP may otherwise have for pursing capital expenditure projects. Specifically, this may assist in mitigating any risk that a DNSP could over-specify the terms and conditions needed to achieve "firmness".	Network planning and investment
6	Consider how to provide effective and clear information to consumers regarding their DER capability and how to maximise value from their investment.	Procurement of NSS Co-optimisation across multiple markets
7	An options study on how to address the potential risk of stranded assets under a high DER scenario.[87]	Network tariffs
8	A review of pricing principles for residual network charges to remove the negative distribution effects on those consumers who cannot afford to own DER resources and to reduce the incentive to go off-grid.[88]	Network tariffs
9	Develop a transparent and credible methodology on how the DNSP calculates prices for DER services.	Procurement of NSS
10	Conduct a technical assessment of the ability of distribution networks to manage to increase DER penetration and whether to develop threshold tests to identify where DER penetration could have a material impact on distribution network security and power quality. This could help to inform regulatory assessment of expenditure proposals.	Distribution System Operation Access and connection Network planning and investment
11	Discussion and identification of the circumstances where separation of the distribution system operation role and the network owner would be necessary and consideration of how to implement such separation.	Distribution System Operations
12	A review of current Rules that could prevent different network tariffs being considered (e.g. export tariffs under NER clause 6.4).	Network tariffs
13	Consider the role of reliability standards under a high DER scenario and in particular whether some form of "export reliability standard" is required. This new standard would create an obligation on DNSPs to ensure that their networks have sufficient hosting capacity to accommodate more DER as existing capacity becomes exhausted.	Access and connection Network planning and investment
14	Develop an open framework for collecting and sharing data across market participants. It will be essential for networks to have visibility of the physical operation of DER participating in the wholesale market and other commercial platforms. Similarly, retailers will need to know when distribution businesses	Co-optimisation across multiple markets Distribution System Operations

[87] The ENA/CSIRO Roadmap has modelled a scenario that partially addresses this risk where electrification of transport could make a substantial contribution to efficient network capacity utilisation. (See page 34)

[88] ENA/CSIRO Roadmap recognises this risk when it states *"Emergence of the potential for off grid and competition in network services to lead to an unplanned and disruptive break down of the funding of the commons of a shared network service capable of integrating efficient levels of centralised generation and distributed energy resources that meet customer needs"* (page 21). The Roadmap proposes that *"By 2027, customer interests are protected by strong and effective customer safety net arrangements which underpin confident participation in new service markets, while protecting vulnerable customers from hardship in a targeted way."* (page 21)

No.	Future work	Elements
	call on DER services and control output at DER sites as this impacts on their hedging positions and liabilities to the wholesale markets. The industry should come together and develop a common framework for information sharing which recognises all interests and information needs.	Network planning and investment

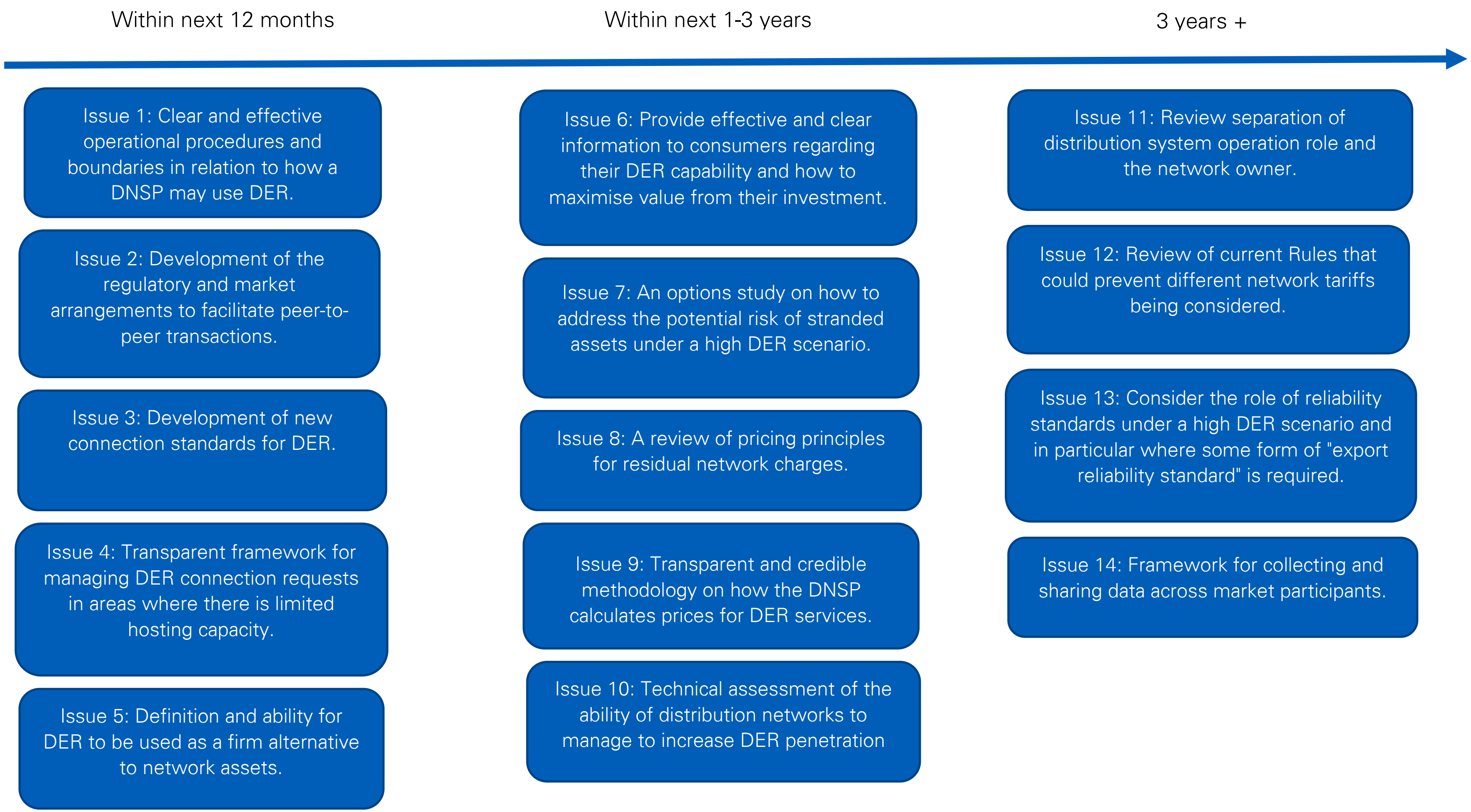
11.4 Suggested sequencing and timing of further work

Given the extent and diverse nature of these areas for further work, we have also considered the timing and appropriate sequencing of conducting the analysis for each issue. As a first step to aid discussions, we have organised the 14 issues into three time-periods where we consider the issue needs to be resolved:

1. Within the next 12 months;
2. Within the next 1 to 3 years; and
3. After the next 3 years.

This is mapped out in Figure 12.

Figure 12. Proposed Sequencing of Future Work to address identified policy gaps



Appendix A: ENA/CSIRO Roadmap

In 2015, the ENA and CSIRO formed a partnership to develop a blueprint for transitioning Australia's electricity system towards a customer-oriented future delivering better customer outcomes. This was in response to the recent experience of electricity network service providers in managing the impacts resulting from significant uptake by customers of rooftop solar PV in response to very generous subsidies, as well as the expected future impacts of two way power flows originating from DERs. This work sought to build on the CSIRO's 2012-13 Future Grid Forum in which four scenarios were modelled (i.e. Set and Forget, Rise of the prosumer, Leaving the grid and Renewables thrive) out to 2050. Each scenario identified a potential energy future which varied greatly in the adoption of new technology, the level and type of customer engagement and the role of the central electricity network. These scenarios were each updated as part of the ENA/CSIRO Roadmap. All four scenarios displayed six common features:

- Network-centric to customer-centric decision power;
- Centralised to hybrid / decentralised technological architecture;
- Dispatchable generation providing for increasing decarbonisation and dispatch ability, intermittency and inertia challenges;
- Regulated natural monopolies increasing their exposure to competitive forces and product substitution;
- 30–50% of Australia's electricity volume (MWh) served by distributed generation; and
- Electricity networks continuing to play a critical set of roles in 2050.

These common features and unique characteristics of each scenario provided an important framework for identification of the potential electricity network transformation outcomes to be addressed in the Roadmap.

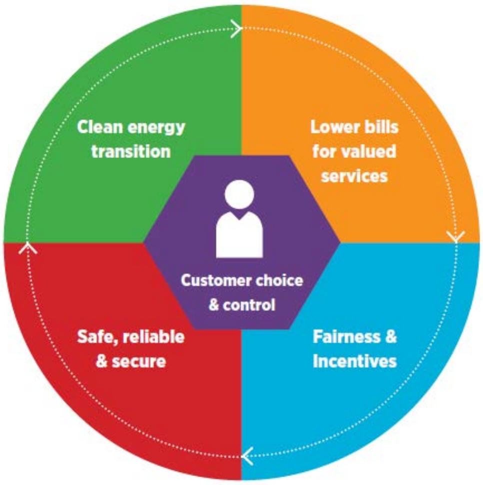
A.1 Roadmap objectives and balanced scorecard

The Roadmap is seeking to enable a seamless, cost-effective electricity system, from generation to end use, capable of meeting the clean energy demands and capacity requirements of this century, while also allowing consumer participation and electricity use as desired. Specifically, the ENA/CSIRO has described a need for electricity networks to transform in order to support:

- A significant scale-up of clean energy;
- 100% customer participation and choice (including distributed generation, demand-side management, electrification of transportation, and energy efficiency);
- 100% holistically designed system (including potential AC-DC hybrid configurations);
- Competitiveness and value creation; and
- A reliable, secure, and resilient grid.

The ENA/CSIRO have developed a balanced scorecard to guide the Roadmap's development as shown in Figure 13 below.

Figure 13. ENA/CSIRO balanced scorecard of customer outcomes



Source: ENA/CSIRO, Electricity Network Transformation Roadmap: Final Report, April 2017

A.2 Work Streams and Milestones

The Roadmap presents the findings from 18 months of work informed by extensive stakeholder consultations and expert analysis included in 19 consultancy reports. The Roadmap is defined across five work streams of transformational focus:

- **Customer oriented electricity –** Customers are at the centre and will largely drive changes to the electricity system depending on their uptake of new technologies to take control of their electricity consumption. Some customer may choose to go off-grid.
- **Carbon abatement –** There are available policy options to enable least cost carbon abatement supported by measures to maximise capacity utilisation.
- **Incentives and network regulation –** Tariff reform, particularly the introduction of an opt-out demand based tariff, will provide incentives to improve the efficiency of energy delivery through DER.
- **Power system security –** The maintenance of power system security with a large penetration of customer DER will require new protection systems and power systems' forecasting and planning approaches.
- **Intelligent networks and markets –** Advanced network operation mechanisms and tools will be required to ensure the safe, reliable and efficient operation of a highly distributed energy resources distribution system; customer DER will provide network support to distribution networks procured through market based mechanisms (e.g. contracts).

The Roadmap, itself, is divided into two phases supported by several "no regrets" actions.[89]

- **Foundation Phase (2017 – 2022):** a series of grid modernisation actions to support access and uptake of customer DER and provide the functional capabilities for further grid transformation

[89] No-Regrets Approach: "No-regrets" actions are actions by households, communities, and local/national/international institutions that can be justified from economic, social, and environmental perspectives whether or not natural hazard events or climate change (or other hazards) take place. "No-regrets" actions increase resilience, which is the ability of a "system" to deal with different types of hazards in a timely, efficient, and equitable

- **Implementation Phase (2023 – 2027):** further activities required to support enhanced customer choice and value through advanced networks operations, markets mechanisms for DER procurement, and optimised renewables integration.

Of these work streams, the chapters (findings) on pricing and incentives, power system security, grid transformation and network optimisation platforms are of most relevance to describing the ENA/CSIRO proposed approach to establishing a DER market for NSS. Specifically, these chapters capture the following:

- Chapter 7: Pricing and Incentives – the role network tariffs may play in incentivising efficiency and innovation in both investment and operation of DER.
- Chapter 9: Power System Security – proposed actions to maintain security and reliability of the national electricity market, while facilitating the integration and management of DER, and the rise in active consumer response to provide effective management of the interface between the distribution system and the wholesale market.
- Chapter 10: Grid Transformation – transformative steps towards a more sophisticated and intelligent network, allowing for system resiliency, stability and cost reductions and the integration of new technologies and equipment.
- Chapter 11: Network Optimisation and Platforms – approaches to integrating DER will also enable the provision of real time services while maximising the operational efficiency of the network.

As part of these chapters, the ENA/CSIRO have identified a series of milestones out to 2027 which guide ENA/CSIRO proposed transformation of the electricity system. Table 8 below lists the milestones established by the ENA/CSIRO for each chapter under the two phases of the ENA/CSIRO review.

A.3 Pathway to a market model for NSS

A key feature of the ENA/CSIRO Roadmap is a proposal leading towards the development of a market for NSS only. This market is to be developed over the assessment period 2017–2027 and provides for three main components:

- The development of ANO tools to assist with distribution planning and operation in light of high levels of renewable energy and DER. KPMG notes these tools are fundamentally an evolution of the existing tools used by the market, developed in response to the increasing complexity engendered by penetration of these technologies across the network. This is also recognised by the ENA/CSIRO as an extension of the current functions of a utility.[90]
- The development of a NOM through which a distributor may procure NSS from customers or via other market actors. The ENA/CSIRO recognise this form of procurement may evolve over time from direct transactions between distributors, DERs and/or market actors, to more sophisticated use of digital platforms and for broader scope of potential products to be traded. Specifically, this process is expected to result in a dNOM later in the assessment period facilitating the procurement and automation of real time network optimisation services.

  The ENA/CSIRO note the development of a NOM (or dNOM), does not "foreclose the future potential for alternative market structures where they are justified."[91] Further, the ENA/CSIRO

manner. Increasing resilience is the basis for sustainable growth in a world of multiple hazards (see Heltberg, Siegel, Jorgensen, 2009; UNDP, 2010).

[90] ENA/CSIRO, Electricity Network Transformation Roadmap: Final Report, April 2017

[91] Ibid.

recognise there to be a range of essential functions that are extensions of the current distribution network responsibilities. These functions are considered an appropriate base for establishing a market for NSS.

The ANO tools and NOM are to be integrated in their functions, whereby the ANO tools identify the need for network support services while the NOM sets out the method for procuring those services from the market. Importantly, the NOM would only procure non-network support services. A distributor may continue to meet its needs internally through building / reinforcing its own network or through the development of non-network options itself.

In terms of roles to be performed by the distributor, the ENA/CSIRO have assumed that there will be no change to the current roles of a distributor in its capacity as DNO or DSO over the assessment period.

- Assignment of residential and small business customers to a new range of demand based electricity tariffs, enabled by a high penetration of smart meters. These tariffs take into account future uptake of new technology and are offered to customers through a range of retail price offerings and structures with the right to opt-out, effective customer support and decision making tools, and reforms to government concession schemes.

  By the end of the assessment period, these tariffs will facilitate selling of DER products or services to networks directly or through agents allowing for dynamic and locational network orchestration of these resources.

A.3.1 Energy market considerations

The ENA/CSIRO consider there to be "*an intrinsic relationship between a potential future distribution level energy market and the development of the NOM. …..because the same distributed energy resources can provide services and be compensated in both markets.*"[92]

The report confines its description to a market for NSS only (NOM). In relation to the integration of a NOM with other DER related product or service markets, the ENA/CSIRO note:

> *"While the ideal approach may be to develop consistent market arrangements for both purposes, this would require prejudging the future development of nascent energy markets and digital platforms. The development of NOM processes and structures represents a no regrets approach which avoids unnecessary delays but would not foreclose the future potential for alternative market structures where they are justified."*[93]

A.4 Potential Roadmap benefits

In developing the Roadmap, the ENA/CSIRO commissioned Energeia to undertake modelling to understand how two proposed waves of distribution network tariff reform might improve customer outcomes through better integration of DER into the networks. The network cost model developed by Energeia and CSIRO is the largest built in Australia covering 14 distribution network businesses with scenario forecasts of demand and consumption and the uptake of DER for a sample of 2,600 customers every year to 2050 at 1,800 zone substations across Australia.

The potential outcomes were assessed against the ENA's balanced scorecard for six different scenarios for electricity network tariff structures and incentive mechanisms. These included a transition from the

[92] Ibid.
[93] Ibid.

current volume based tariffs to demand based tariffs in the "First Wave" by 2021 and new incentives for customers to sell DER services to networks in the "Second Wave" including 'standalone power system tariffs' for customers with self-sufficient, on-site DER.

An important finding was the major differences in customer outcomes with an "Opt Out" network tariff policy compared to the current network tariff policy of "Opt In". For the preferred scenario (Scenario 5[94]), an "Opt Out" policy might result in customer savings of over 10% per year on average network bills by 2026 and economic benefits of $1.8 billion when compared to the base case scenario. By 2050, an 'orchestration' where networks buy grid services from DER customers, could replace the need for $16.2 billion in network investment, avoid cross subsidies, and lower average network bills by around 30% compared to today.

Table 8. ENA/CSIRO Roadmap Milestones (Chapters: Pricing & Incentives, Power system security, Grid Transformation, and Network Optimisation & Platforms)

Foundation Phase (2017-22)			
Pricing and incentives	**Power system security**	**Grid transformation**	**Network optimisation & platforms**
	Milestone 1: By 2018, the central and transformed role for the transmission system to support power system security has been defined. **Milestone 2:** By 2018, market based approaches for providing efficient capacity, and balancing and ancillary services have been established, including a set of fully tested options that would cater for a very low emission generation mix.	**Milestone 1:** By 2018, the approaches and protocols to address the management and exchange of information between networks and distributed energy resources participants and allow effective coordination of the system in real time and supports full interoperability are determined. These approaches would be established with the highest levels of security including data management, information privacy and cyber security	**Milestone 1:** By 2018, networks with very high distributed energy resources levels are implementing basic NOM functions to procure locational distributed energy resources services for network support, either directly from customers and/or through their agents.
	Milestone 3: By 2019, an initial approach has been developed for coordinating and optimising decisions across the power system as a whole, which includes more effective interfacing between the	**Milestone 2:** By 2019, an integrated suite of advanced network planning models, techniques and distributed energy resources services valuation methods have been established as foundational to the	**Milestone 2:** By 2019, a basic set of Advanced Network Optimisation (ANO) functions are performed where networks with very high distributed energy resources levels progressively implement advanced network

[94] Scenario 5 is modelling as a move towards locational and dynamic pricing mechanisms. Instead of a Critical Peak Price option, the scenario models an incentive structure whereby consumers receive an incentive in exchange for operational access to energy output from batteries at the local level. Scenario 1 is the base case approach to network tariff and incentive design whereby the current tariff structures, peak and residual charge mechanisms and tariff assignment mechanisms, as proposed by the DNSPs in their inaugural Tariff Structure Statements, are retained over the period to 2050. See Energeia, Network Transformation Roadmap: Work Package 5 – Pricing and Behavioural Enablers, August 2016, page 5.

Foundation Phase (2017-22)			
Pricing and incentives	**Power system security**	**Grid transformation**	**Network optimisation & platforms**
	Independent Market Operator (IMO) and the distribution network connection points.	mainstreaming of distributed energy resources services as non-network alternatives. **Milestone 3:** By 2019, an integrated suite of distributed grid intelligence and control architectures and tools have been agreed as foundational to the safe, reliable and efficient operation of a high distributed energy resources distribution system.	planning tools, distributed grid intelligence and control and advanced network operation techniques.
	Milestone 4: By 2020, new tools and models have been developed to provide better forecasting to better anticipate where environmental and system constraints could lead to system security issues.	**Milestone 4:** By 2020, an integrated suite of advanced network operation mechanisms and tools have been agreed as foundational to the safe, reliable and efficient operation of a high distributed energy resources distribution system which also contributes to overall power system security.	**Milestone 3:** By 2020, collaborative projects demonstrating the integration of Advanced Network Optimisation (ANO) functions and NOM procurements have validated direct and market based orchestration of distributed energy resources as a reliable non-network alternative.
Milestone 1: By 2021, early transition to better tariffs where residential and small business customers are assigned to a new range of demand based electricity tariffs, enabled by a high penetration of smart meters. These tariffs take into account future uptake of new technology and are offered to customers through a range of retail price offerings and structures with the right to opt-out, effective customer support and decision making tools, and reforms to government concession schemes. **Milestone 2:** From 2021, new prices will be	**Milestone 5:** By 2022, advanced protection mechanisms have been developed, trialled and validated to better address distributed energy resources impacts and enhance system operation and security	**Milestone 5:** By 2022, the full suite of Advanced Network Optimisation (ANO) tools have been trialled and validated across a diversity of Australian network topologies and DER "scenarios".	

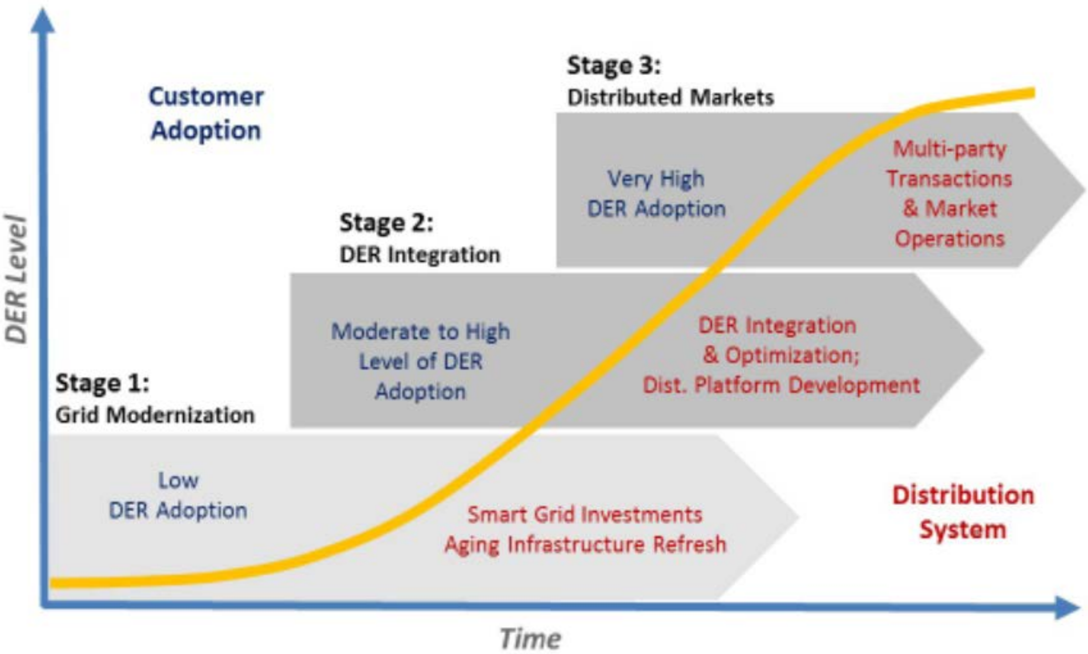
Foundation Phase (2017-22)			
Pricing and incentives	**Power system security**	**Grid transformation**	**Network optimisation & platforms**
introduced to reflect new and differentiated services desired by customers, including self-sufficient supply of energy at some times, and the ability to trade energy on non-traditional platforms (peer-to-peer arrangements). **Milestone 3:** From 2021, micro-grids and standalone power systems will be a feasible alternative to traditional grid connection.			

Implementation Phase (2023-27)			
Pricing and incentives	**Power system security**	**Grid transformation**	**Network optimisation & platforms**
			Milestone 4: By 2023, networks with very high distributed energy resources levels are performing an integrated set of Advanced Network Optimisation (ANO) functions and NOM procurements as mainstream activities to ensure technical stability, economic efficiency and market animation.
Milestone 4: By 2027, networks buying grid services from customer power systems as an alternative to grid investment. This includes network orchestration using distributed energy resources on a dynamic, locational basis, resulting in one-third of customers selling their distributed energy resources services to networks, directly or through their agents.			**Milestone 5:** By 2027, a feasibility study, cost benefit analysis and conceptual design of a digital Network Optimisation Market (dNOM) is complete.

Appendix B: Distribution system transformation

The ENA/CSIRO have referenced the work of De Martini and Kristov of the Berkeley National Laboratory (BNL) in describing the three stages of transformation of a distributor when faced with high penetration of DER.[95] This model has provided important learnings that have informed the Roadmap development and the "no regrets" actions developed within the report.[96] Figure 14 below shows the De Martini/Kristov stages of transformation.

Figure 14. Three stages of distribution system transformation



Source: Berkeley National Laboratory: Distribution systems in a high distributed energy resources future. Planning, Market Design, Operation and Oversight. October 2015

De Martini and Kristov in developing their framework have noted:

> *"This framework is based on the assumption that the distribution system will evolve in response to both top-down (public policy) and bottom-up (customer choice) drivers. Thus, each stage*

[95] Lawrence Berkeley National Laboratory, De Martini & Kristov, *Distribution Systems in a High DER Future: Planning, Market Design, Operations and Oversight*, October 2015. Although this report was developed for the USA power sector, it does provide a useful generic framework that can be applied in Australia.
[96] Specifically those actions developed under the Network Optimisation and Markets work stream.

represents the effects of both a set of public policies and increasing customer adoption of DERs. Each level includes additional functionalities to support the greater amounts of DER adoption and the level of system integration desired. Each level expands on the capabilities developed in the earlier stage."[97]

These stages account for both policy and consumer driven investment in DER.[98] As part of the transition from one stage to the next, De Martini/Kristov considered the necessary changes in both the functions and systems of the distributor, as well as the potential for DER to transact given certain thresholds of investment in DER. An overview of each of the three stages is provided below:

- **Stage 1: Grid modernisation –** under Stage 1, investment in DER remains low without requiring significant changes to the existing network. In this stage, policy promoting investment in DER remains under development.
- **Stage 2: Integration of DER –** during this stage, investment in DER increases materially to a level where such resources may provide system benefits, while also resulting in issues associated with bi-directional flows. Levels of this nature may require improvements in the distributor's functions and network capabilities, including planning and operation of the network and investment in network control technologies.
- **Stage 3: Market establishment –** Stage 3 represents the establishment of a DSO model allowing for DER, consumers and third parties to trade in services beyond the distributor. Here investment in DER remains high with policy support leading to reform of the energy sector and the creation of a new market for grid services.

The evolution from one stage to another is likely to be driven by a range of factors, including technology and penetration rates, as well as customer preferences. To the extent that stages require different regulations to support the transition, there will also be an economic justification to the evolution as the regulator may conduct a cost/benefit analysis before agreeing to regulatory reforms.

This model described by De Martini/Kristov is applicable to distributors around Australia when accounting for the level of investment in DERs and their integration into the network. While there has been a significant uptake in rooftop solar by residential and SME customers across the NEM, investment in other DER remains low at present. This is a reflection of certain technologies (such as battery storage) that are only now reaching a commercially viable option for these customers, while other categories of market participant, such as aggregators, have only recently been established under the NER. As a result, distributors have had little opportunities to integrate and importantly optimise the use of these technologies and service offerings into the broader operation of the network. As investment in these technologies continues to grow, distributors will have more opportunities to 'learn' how best to integrate these resources into the system and therefore maximise the benefits associated with their operation.

Furthermore, as noted above, only Victoria has rolled out AMI across the majority of its distribution networks. Other states are only now ramping their investment in AMI technology, thanks to incentives driven by the AEMC's Power of Choice review and the expiry of the New South Wales Solar Bonus Scheme among others. The capabilities associated with AMI, in particular the ability to 'control' energy or load from a DER, are vital to the established a well-functioning DSO. A DSO focused only on the Victorian market, and within that a local defined area, may benefit from the existence of AMI in the state. However, a broader NEM wide DSO platform would require significant investment in order to provide for the smart grid technologies envisioned by BNL, required in order to operate a DSO effectively.

[97] Ibid.
[98] Ibid.

Based on this assessment, Australian distributors remain at the bottom of the evolution curve reflecting a lower adoption of DER to date, as well as further investment requirements in smart grid technologies. Victoria is the current exception to this and may find its self slightly further up the curve having previously mandated the rollout of advanced metering infrastructure across its distribution networks, although it may still be classified under "Stage 1".

Contact us

Cassandra Hogan
Partner
T: +61 2 9455 9642
M: +61 402 060 250
cjhogan@kpmg.com.au

Eamonn Corrigan
Director
T: +61 2 335 8555
M: +61 428 231 220
Ecorrigan1@kpmg.com.au

Harry Koller
Director
Tel +61 3 9288 6337
Mobile 0400 836 333
hkoller@kpmg.com.au

kpmg.com.au