AEMC

REVIEW

Australian Energy Market Commission

ECONOMIC REGULATORY FRAMEWORK REVIEW

INTEGRATING DISTRIBUTED ENERGY RESOURCES FOR THE GRID OF THE FUTURE

26 SEPTEMBER 2019

INQUIRIES

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ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

FOREWORD

The electricity sector is undergoing a major transformation. Distributed energy resources – such as solar panels, battery storage and electric cars – are fundamentally changing the way consumers engage with energy markets. They can help to deliver clean, secure, reliable and low cost power for everyone on the grid.

In this context, the focus of the 2019 Economic regulatory framework review is the integration of distributed energy resources into the energy market system, which is one of our strategic priority areas of reform. In this year's report, we set out a range of options to create more dynamic markets and manage network challenges created by increasing penetration rates of distributed energy resources. We highlight work that is already underway to implement distributed energy resources effectively, what we are planning to do next and whether we see any gaps. Some issues require urgent action. For others, we have time to consider the broader implications for the regulatory framework.

Regulation should be centred on outcomes that maximise benefits to all consumers, and designed to promote innovation and competition. Consumers should be rewarded for integrating their behind the meter appliances with the network. We think reforms to regulation are necessary to make this a reality, particularly to the way electricity 'exports' and 'imports' are priced, and to allow for different access and connection services to be provided by network distribution businesses. Through the Distributed Energy Integration Program (DEIP), the Commission will work closely with stakeholders who intend to submit rule change requests to progress reforms to distribution access, connections and charging arrangements.

The successful transition of the energy sector requires a shared vision, and cooperation and collaboration between all parts of the sector. The Energy Security Board plays an important role in coordinating the reforms undertaken by all parts of the industry. The Commission will continue to work with the Energy Security Board, and in particular, through its *Post 2025 Market Design* project to realise the benefits of the future energy market.

John Pierce AO

Chair, Australian Energy Market Commission

EXECUTIVE SUMMARY

1 Australians have embraced distributed energy resources (DER) with enthusiasm. Consumer uptake of DER increased significantly with the installation of roof-top solar PV systems in the late 2000s and this trend has continued to the present. Consumers have also started to adopt new forms of DER as they become available to help better manage their electricity usage. Consumer uptake of DER is expected to continue to increase as costs decline and availablility increases.

2 DER will be a key part of the future Australian electricity system – it needs to be integrated efficiently for the benefit for all electricity customers, regardless of whether they have access to DER or not. The potential benefits of efficient integration DER for all customers are substantial and the timely development of a supportive regulatory framework is essential. Conversely, consumers will bear the cost of DER not being integrated into the electricity system efficiently. A system that does not provide consumers with choice or reward supportive behaviours could drive up costs. Electric vehicles could add to peak demand instead of smoothing it, zero marginal cost solar generation could be inefficiently constrained, prices could become more volatile instead of less, and consumers could be driven into supply arrangements where developers or local monopolies control their supply and appropriate their DER benefits.

3 Actions and regulatory reforms are required to integrate DER into the electricity market and to optimise benefits of DER for all electricity system users. A substantial work program is already underway through market bodies, consumer groups, regulated network businesses and government agencies.[1] The Commission has consulted widely to understand the nature and magnitude of the issues on DER integration and the different work programs that aim to address various aspects of integration. Commission staff worked closely with consumer groups through the National Consumer Roundtable on Energy to consider DER integration from a consumer centric perspective.

4 In this *2019 Economic regulatory framework review* (2019 Review), the Commission seeks to place this important and necessary work within the overall context of the required regulatory framework and identify gaps where actions and/or reforms are needed. Through this review, the Commission also monitors developments and considers improvements to regulatory and energy market arrangements where necessary.

5 In this report, the Commission has identified the following 'tools' that are crucial in integrating DER and optimise benefits for all customers:

- customer reward pricing
- distribution system access and connections
- information to enable decision making
- maintaining security and reliability.

1 DER integration is not a task that could be achieved by one organisation or one part of the industry alone. The Commission acknowledges that all parts of the industry are working towards the efficient DER integration and there are a number of work programs towards this goal.

A future consumer centric electricity system

6 DER uptake in Australia has increased significantly in the last decade, driven mainly by consumers. The national electricity market (NEM) saw nearly 6,000 MW of small-scale solar photovoltaic (solar PV) generation installed between 2010 and 2018. The trend in DER uptake is likely to continue. By 2039, Australia is expected to have one of the most decentralised electricity systems in the world. Box 1 below shows a forecast of future DER penetration in Australia.

BOX 1: FORECAST DER PENETRATION BY 2039

- By 2039, Australia is forecast to have approximately:
  - 16,000 MW of residential rooftop solar PV capacity
  - 7,500 MW of residential battery storage
  - 25% of vehicles being electric vehicles (EVs) – including hybrids.
- By 2050, almost two out of three customers are expected to have DER.

Source: Graham et al., Projections for small scale embedded energy technologies, June 2019, p. 44, 49, 52. See also ENA and CSIRO, *Electricity Network Transformation Roadmap: Final Report*, April 2017, p. 5.

7 This high level of uptake means that DER is likely to be a significant part of the Australian electricity system in the future, and will play an important part of an electricity system that is diverse and flexible.

8 Consumers' interactions with the electricity system are also changing with the increasing uptake of DER. Consumers who have invested in DER will be able to play a more active role in the electricity system. They will be able to generate electricity to meet some of their own needs, have the ability to control when and how they use it, and also inject surplus generation or stored energy back into the electricity grid. The emerging trend in the uptake of domestic batteries dramatically increases opportunities for consumers to actively participate in energy and ancillary services markets, and in emerging markets such as network support. New technology such as electric vehicles will also bring different dimensions to electricity system usage.

9 The high level of DER uptake is also likely to facilitate the emergence of different market participants. The future is likely to see the growth and increasing sophistication of third party businesses to provide energy management services. The energy retail model could also evolve, with new entrants providing innovative offerings to consumers. As behind-the-meter battery storage becomes more prominent in the future, there may also be different providers competing to provide aggregator services for energy, balancing services and network support. Changes in rules and regulations may also create new types of service providers. For example, the Commission’s Wholesale demand response mechanism draft rule has proposed to create a new category of participant – demand response service provider (DRSP).

10 Consumers are likely to have different preferences and requirements from the electricity system and to interact with it differently. Box 2 below provides some examples of the

potential different interactions between consumers and the electricity system.

BOX 2: DIFFERENT WAYS OF INTERACTING WITH THE ELECTRICITY SYSTEM IN THE FUTURE

In the future, consumers with access to DER may interact with the electricity system in one or a combination of the following ways:

- Drawing electricity from the grid
- Generating electricity for their own consumption only (becoming less reliant on grid supply)
- Buying, trading or selling energy, either to a retailer or through other platforms such as peer-to-peer trading
- Participating in new services markets such as providing demand response, network support or ancillary services to the wholesale energy market
- Supplying energy (or other services) to community projects such as a community battery.

11 As consumers' interactions with the electricity system evolve, so will their expectations and required standard of service. In the past, the electricity system was predominantly used to transport electricity one way – from centralised generation to end user. In a high DER future, the electricity system (especially at the distribution level) is increasingly likely to have multi-directional flows and become a platform to support different services, such as access to various markets, that future electricity system users may demand. The future electricity system and the regulatory framework need to be able to support these and potentially many other varieties of use.

Successful DER integration should be judged from the consumer's perspective

12 For DER owners, efficient integration would mean they have the opportunity to maximise the return on their investment through the operation of their DER. This could range from using their DER for bill reduction, to access and participate in the growing number of new energy services markets, or a combination of both.

13 The efficient integration of DER could also provide significant benefits to non-DER owners in the form of lower total system costs. DER is a flexible resource from both a load and generation perspective. Generation assets (such as solar PV and batteries) could drive down energy costs by providing low cost energy,[2] as well as ancillary services in competition with traditional providers. Devices or programs that promote and enable load flexibility could help deliver more efficient use of existing network infrastructure. Effectively integrated DER can also provide services that support the reliability and security of the system, helping AEMO and network businesses maintain a reliable and secure system at a lower cost.

2 DER such as roof top solar system can generate electricity at zero marginal costs when the sun is shining.

What is the role of networks in supporting DER integration?

14 The core roles of networks in a high DER future are likely to remain the same as today. Network service providers will continue to be responsible for transporting electricity and providing safe, secure and reliable supply of electricity as a monopoly service provider.

15 However, how they undertake this role could be different in a number of key respects. In particular, how the electricity distribution network is operated and the services provided by distribution network service providers (DNSPs) could change. A high DER environment could mean that DNSPs need to alter aspects of their operation, from transporting electricity one-way to being platforms for multiple services, facilitating electricity flows in multiple directions and facilitating efficient access for DER so that they can provide the greatest benefits to system as a whole. This change is likely to have implications on aspects of the regulatory framework.

16 Consumer choices about how and when they consume and export electricity should drive the transformation of the energy sector. It is therefore increasingly necessary for networks to understand and reflect consumer views, preferences and priorities in their regulatory proposals. Early and meaningful consumer engagement – on issues such as tariff structures and investment to address export constraints – is important now more than ever.

What are the challenges to efficient integration?

Increasing DER penetration is starting to affect distribution network operations

17 DNSPs are starting to face technical issues as consumers continue adopt DER, with the management of voltage fluctuation (and the resulting export constraints driven up upper voltage limits) being one of them.

BOX 3: VOLTAGE FLUCTUATION EXPERIENCED BY DISTRIBUTION NETWORKS

- **Voltage rise issues caused by solar PV generation.** The export of power from solar generation to the network results in an increase in the network voltage. Many inverters are designed and configured to reduce output and trip (i.e. disconnect from the grid) near the upper network voltage limit. This often occurs when sunlight conditions are most conducive to solar generation.
- **Voltage drop can also create issues.** Conversely, in late afternoon, or as a result of cloud cover, solar output reduces and under some loading conditions can cause voltage to fall below the regulated limit.

18 The Commission has observed that some DNSPs are already restricting DER exports in parts of their network that are constrained. These restrictions are being imposed as basic connection size or export limits, with some customers facing very low or even zero export limits in areas of the network with high levels of solar penetration. As DER penetration increases in the future, the instances of DNSPs restricting export are likely to increase. Some

DNSPs have signalled that allowed export limits are likely to be reduced even further.[3]

19 The imposition of static export restrictions (e.g. an export limit of 2kW for all household in a particular network area) could lead to uneconomic outcomes. For example total system costs could be lower if more of the existing solar PV installations (providing zero marginal cost energy) are able to inject energy into the electricity system instead of other more expensive energy sources such as grid scale conventional generators.

20 The nature and magnitude of these technical impacts differ between DNSPs (and sometimes within a DNSP's operating area) as the penetration of DER differs between locations. The impact of technical issues resulting from DER uptake also varies by DNSP. DNSPs that have greater network capacity and lower solar PV penetration are experiencing fewer issues while others, such as SA Power Networks and Energy Queensland, are experiencing greater technical impacts.

Consumer representatives' concerns about current charging arrangements

21 Some consumer groups have also expressed concerns that the current charging arrangements, where the cost of the distribution network is recovered solely through consumption charges, are leading to inequitable outcomes, with the cost of DER integration being borne by all consumers regardless of whether they own DER. They are concerned that customers who do not have (or cannot access) DER will not have any means to mitigate any additional network expenditure to facilitate additional DER export. They consider their concerns could not be adequately addressed under the framework that relies on consumption only charging and this is exacerbated by the lack of progress in the implementation of consumption-based network pricing reform.

22 Inequitable outcomes can also arise from DNSPs taking a 'first in, best dressed' approach to DER connections, especially in relation to the consumer's ability (or restrictions on their ability) to inject energy to the grid. The Commission understands that in many network areas, consumers who were early DER adopters are able to export energy into the grid with high export limits (e.g. 10 kW). However, as DER uptake increases and technical issues such as voltage limits are reached, new DER installations receive either a very low or zero export limit.

Reforms to support efficient DER integration

23 Consumers will bear the costs of DER not being integrated efficiently into the electricity system. At best, poor integration of DER could mean that the electricity system would not realise all the benefits that the significant investment in DER could provide. At worst, consumers would bear additional costs through poor planning decisions, an inability to realise benefits from their DER investment, and potentially inefficient investment such as over building network capacity.

3 Recent changes to technical standards mean that electricity exports from new solar PV installations are unlikely to cause technical or safety issues for DNSPs. This is because exports from those installations will automatically reduce or stop as (voltage based) capacity limits are reached, meaning that some solar PV owners are not able to sell their output.

24 While the regulatory framework is flexible and robust, and is able to support DER integration in general, some reforms are needed in order to deliver the best outcomes to consumers in a high DER future. DER integration also requires whole-of-sector effort and cannot be done by one entity in isolation. The 2019 Review has identified a number of actions and recommendations to support DER integration. These are discussed further below.

Short term strategies that DNSPs can implement

25 There are some strategies that can be implemented to increase network's 'hosting capacity' to enable more DER to be connected or reduce the instances of export constraints in the short term. Some of the strategies that are currently being implemented by DNSPs with high or growing DER penetration, such as SA Power Networks and Endeavour Energy, include:

- Requiring new PV connections to have smart inverter settings that are capable of providing reactive power control
- Changes to voltage control and adjusting network nominal voltage to provide more 'headroom'
- Shifting controlled load (such as hot water storage) periods to utilise solar output.

'Building out' the network is not an efficient solution, but dynamic export limits can be an interim solution

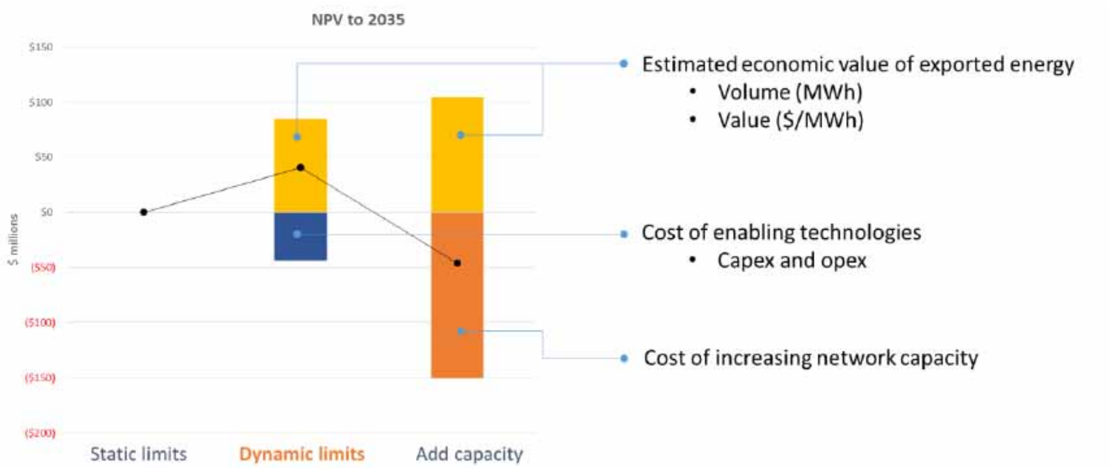
26 DNSPs could also augment their networks to increase their capacity to integrate more DER. However, network augmentation is often costly and an inefficient solution to provide additional network capacity that is generally needed for only certain times.

27 A potentially more efficient solution to integrating a higher level of DER is the application of dynamic export limits. Instead of applying a low static export limit to all consumers, this solution recognises that technical issues caused by DER exporting to the grid generally do not occur frequently, and a DNSP may only need to constrain DER output on occasions so that its networks can operate within capacity.

28 Dynamic export limits are being considered by DNSPs such as SA Power Networks that is already facing a high level of DER penetration. SA Power Networks has proposed to implement flexible export limits in the 2020-25 regulatory period. Under SA Power Network's proposal, consumers will be able to choose between a static limit that applies at all times (currently 5 kW but likely to reduce to 3 kW) or a dynamic limit of 10kW that SA Power Network can reduce at peak times.

29 Importantly, SA Power Networks' proposal to implement dynamic export limits is supported by a cost-benefit analysis. Figure 1 below provides a graphical illustration of the results.

Figure 1: SA Power Networks' cost benefit analysis of flexible export limits



Source: SA Power Networks

30 SA Power Network's analysis showed that the implementation of dynamic export limits provides a greater net benefits compared to static limits or adding network capacity through augmentation. Crucial to its analysis is the estimated economic value of exported energy. The Commission understands that SA Power Networks, with assistance from expert consultants, developed a methodology that is based on the regulatory investment test for distribution (RIT-D). As DER penetration increases, there will be an increasing need for a consistent methodology that is applied for all DNSPs conducting similar analysis.

BOX 4: THERE IS NEED FOR A COMMON VALUE OF CUSTOMER EXPORT METHODOLOGY

Through the DEIP DER valuation package of work, the Commission will work together with ARENA, AER, consumer groups and other stakeholders to develop a standard methodology to estimate value of customer export, which could be used to determine the value of a marginal increase in export hosting capacity.

31 Implementing dynamic export limits (as well as other solutions to improve a distribution network's ability to integrate more DER) is likely to require a level of additional DNSP expenditure. Some expenditure could be targeted at building a LV hosting capacity model, sourcing data as part of implementing LV monitoring and the calculation of flexible export limits. The level of additional expenditure required is likely to differ between DNSPs as they each have varying levels of DER penetration currently and potentially different forecast uptake.

32 As discussed in the *2018 Economic regulatory framework review*, the Commission considers the incentive-based regulatory framework provides DNSPs the ability to undertake such

expenditure, if it is prudent and efficient.[4] Indeed, DNSPs such as SA Power Networks and Energy Queensland have included DER integration related expenditure in the regulatory proposals for their upcoming regulatory periods, which are currently under consideration by the AER.

BOX 5: AER PAPER TO PROVIDE GUIDANCE ON EFFICIENT DER EXPENDITURE

As the AER is also expecting to receive requests for DER integration expenditure in future DNSP regulatory proposals, it has commenced developing a set of guidelines on how it intends to consider distributor DER integration expenditure in revenue proposals, as well as what it considers as prudent approaches in integrating DER.

The Commission supports the AER in developing this guideline as it provides a level of certainty to DNSPs on how their proposed expenditure will be assessed.

Reforms to the distribution access, connections and charging framework

33 One aspect of the regulatory framework that will have a major impact on efficient DER integration is the distribution system access, connection and charging arrangements.

34 Customers' interactions with the electricity system (and in particular, the distribution network) will be become more diverse in the future. While most customers will continue to use networks to import electricity from the grid, the networks will also be used by other consumers to access new energy services markets. The regulatory framework needs to accommodate this diversity of use and enable DNSPs to develop and price new services that meet the evolving needs of all consumers. Through the DEIP DER Access and Pricing Working Group, the Commission will work with all stakeholders in considering potential new access arrangements that may form part of DNSPs' new service offerings. Some of the potential options could include:

- options to select varying levels of static export limits
- options to choose different levels of access
- implementation of operating envelopes

BOX 6: REFORMS TO THE DISTRIBUTION ACCESS AND CHARGING FRAMEWORK

Through the Distributed Energy Integration Program (DEIP), the Commission will work closely with stakeholders who intend to submit rule change requests to progress reforms to distribution access, connections and charging arrangements.

If rule change requests on access and connection arrangements are not received by early

4 AEMC, *2018 Economic regulatory framework review: promoting efficient investment in the grid of the future,* July 2018.

2020, then as part of the *2020 Economic regulatory framework review* (2020 Review), the Commission will consult on and develop detailed proposals for changes to distribution system access and connection arrangements to support consumers' needs while minimising total system costs.

Export charging needs to be considered together with access and connection arrangements

35 Many stakeholders are acknowledging the issues caused by the current consumption-only charging framework and have suggested that one potential solution is to allow DNSPs to apply a 'use of system charge' to DER exports. However, export charging cannot be implemented as a stand-alone reform.[5] Allowing DNSPs to charge for exports would require consideration of at least the following:

- Level and type of services provided: What level of services would be provided to DER owners in return for payment? What is the impact on DNSPs' revenue requirement?
- Access arrangements: If there are network constraints resulting from DER exporting into the grid, when and how would DER exports be curtailed?
- Connection arrangements: What changes, if any, do we need to make to DNSPs' connection agreements? Should there be some form of optionality through a choice of different types of connection arrangements with different costs and export levels to help manage any challenges that may arise?

36 The consideration of DNSPs' charging arrangements should not be confined to the imposition of export pricing only. Consumers' interactions with the electricity system (and in particular, the distribution network) will be become more diverse in the future. While most consumers will continue to use networks to import electricity from the grid, the networks will also be used by other consumers to access new energy services markets. The regulatory framework needs to accommodate this diversity of use and enable DNSP to develop and price new services that meet the evolving needs of all consumers.

Different options for charging

37 There are multiple ways in which consumers could pay for services that may be offered by DNSPs in the future. Pricing options need not be based on the traditional volumetric (e.g. c/kWh) charges and could entail a combination of fixed connection charges, capacity payments as well as (potentially time varying) volumetric payments.

38 Some DNSPs have also considered applying the concept of 'subscription + top up' where a consumer would pay a regular subscription for an agreed base level of capacity and pay for 'top ups' should they consume or export more than their base subscription level. It may also be appropriate for charging to be agnostic to whether the network is used for export or consumption, e.g. you pay per kWh for your combined import and export.

5 Export charging is currently explicitly prohibited by Clause 6.1.4(a) of the NER.

Is there a need to consider obligations on DNSPs to manage export constraints?

39 There is currently little incentive for DNSPs to invest in measures to reduce export constraints. The network regulatory framework currently imposes no consequences on DNSPs for constraining off DER generation, and similarly provides no benefits for increasing DER hosting capacity where this is in the long term interests of consumers. To the contrary, even if network revenue allowances have been built up on the basis of constraints being addressed then, in the absence of a countervailing output incentive, the operation of incentive schemes such as the efficiency benefit sharing scheme (EBSS) and capital efficiency sharing scheme (CESS) incentivises under-expenditure, with no penalty for under-delivery.

40 There may therefore be merit in considering explicit DNSP incentives for managing export constraints, either through pricing arrangements or as an enhancement to the existing service target performance incentive scheme (STPIS). The Commission will consider the need for such incentives as part of the consideration of access and charging arrangement reforms.

Tools that can support efficient DER integration

Customer reward pricing as a tool to facilitate efficient DER integration

41 DER is not a homogeneous resource. While DER such as a rooftop solar system is a generator of electricity, other DER such as batteries and EVs can both draw and inject electricity to the electricity grid. An important distinction between rooftop solar systems (passive DER) and batteries and EVs (active DER) is that owners of active DER are able to control their operations. Rooftop solar systems can only operate during times when the sun is shining while batteries and EVs can both charge and discharge at times determined by their owners (or operators). Batteries can also be aggregated into virtual power plants (VPPs) where they can be charged or discharged in a coordinated manner. The flexible nature of active DER could provide significant benefits to both owners of DER and electricity system users in general.

42 Batteries can be charged at times when there is an abundance of low cost generation (e.g. times of high solar PV output) and avoid charging, or discharge, during times of known network peaks, enabling a more efficient use of the electricity system.

43 Efficient network consumption pricing would allow DER owners to maximise the benefits from their investment. Differential pricing options that incentivises consumers to charge their batteries or hot water systems when there is an abundance of low cost generation (e.g. times of high solar output) and/or during times of low network usage could significantly lower their electricity bills. Avoiding DER consumption during periods of known network peaks would also enable a more efficient use of the electricity system, benefiting all consumers. Conversely, poor consumption price signals in a future where there is significant uptake of DER could perpetuate the inefficient use of the grid and potentially lead to new round of unnecessary network investment.

44 The AER has held several roundtables with participants across the supply chain, consumer groups, and market bodies, to develop consistent national strategies and principles to pursue tariff reform and facilitate more coherent collaboration between key stakeholders. These roundtables are improving communication between the distributors and retailers to progress

tariff reforms. The AER and ECA have been engaging with numerous stakeholders to explore the practicalities of tariff reform and interactions with other developments.

> **BOX 7: CONTINUE IMPLEMENTATION OF NETWORK TARIFF REFORM**
>
> The Commission strongly supports the AER's continued effort to implement network pricing reforms through the TSS process and roundtables with stakeholders as an additional means to progress network tariff reforms.

Enabling informed decision making

45 Information availability, both to consumers and DNSPs, was raised as a key enabler to the efficient integration of DER at the 'Regulatory DEIP Dive' workshop jointly held by the Commission and the Australian Renewable Energy Agency (ARENA) in June 2019.[6] In a high DER world, knowledge about DER performance, network constraints and market conditions are fundamental to decision making.

What information would support consumers' decision making?

46 Having 'live' and more granular energy data could greatly assist consumers in managing their own energy usage and/or the operation of their DER.

47 Smart (advanced) meters are capable of capturing a range of data about energy flows and voltage levels. However, users and network operators[7] often only see a small fraction of this data, being the historical usage information that is relevant to billing. Coupled with a third party service such as an online app, consumers could see real-time information about their electricity usage or detailed analytics about their appliance usage and associated costs. This information would allow them to change their usage pattern to minimise their electricity bill, if their retailer offers time based or differential pricing.

48 On 1 December 2017, the Competition in metering rule came into effect.[8] Since the commencement of this rule, over 815,823 small electricity customers outside of the Northern Territory, Western Australia and Victoria now have an advanced meter.[9] While this customer-led roll out is progressing faster than expected, it was not without challenges. Some customers experienced significant delays when they requested the installation of smart meters, often as part of the installation of DER such as a rooftop solar system. In response to the delays and consumer frustrations, the Commission made the Metering installation timeframes rule in November 2018 requiring retailers to install smart meters within certain

6 The Distributed Energy Integration Program (DEIP) is a collaboration of government agencies, market authorities, industry and consumer associations aimed at maximising the value of customers' DER for all energy users. The Regulatory DEIP Dive explore how DNSPs will need to operate their networks differently in a high DER future and considered how networks need to be regulated so that the overall costs of electricity supply to all consumers are minimised.

7 With the exception of Victoria

8 The rule transfers metering responsibilities from DNSPs to retailers, and require all new and replacement electricity meters to be advanced meters that meet the minimum specifications under the National Electricity Rules (NER).

9 This figure is the number of advanced meters installed as of 1 July 2019. Source: MSATS data. Almost all customers in Victoria have a smart meter. This is because the Victorian Government mandated a DNSP led roll-out in the mid-2000. For other NEM jurisdictions, the penetration of smart meters is around 10%-15%.

timeframes where the installation request was initiated by the consumer. The Commission has also been working closely with the industry to resolve implementation problems as they arise.

49 The Commission has been monitoring smart meters installation timeframes since the publication of the Metering installation timeframe rule in November 2018. The Commission will extend this monitoring to include all issues affecting the efficient roll out of smart meters in the NEM.

BOX 8: MONITORING SMART METER ROLL OUT

Starting from the final quarter of 2019, the Commission will consult with industry to identify potential barriers to the roll out of smart meters and the use of smart meters to deliver the maximum possible benefits to customers. It will also commence gathering quarterly data from industry, AER and AEMO on the status of the roll out.

BOX 9: REVIEW INTO COMPETITION IN METERING ARRANGEMENTS

The Commission committed to commence a review of competitive metering arrangements in December 2020, when it made the Competition in metering determination in November 2015.

The Commission will commence this review as planned. The results of metering roll-out monitoring as recommended above, along with potential benefits of greater data collection and availability, would be significant issues to this review.

50 In addition to understanding their own usage, consumers will also benefit from having more information on the state of the distribution network in two key ways:

- **Optimising the use of their existing DER assets.** With real time information about prices and constraints, consumers who have invested in batteries could choose to export stored energy at times of high wholesale prices and low exports, or import energy from the grid to charge their batteries at times of low prices and low imports, or provide existing and evolving FCAS and distribution network support services.
- **Making the optimal DER investment decision.** Information on DER that is already connected to the distribution network, or the level of capacity constraints, would allow consumers to determine whether to make long-term investments in solar panels, batteries, demand response or other forms of DER. The level of DER penetration would inform potential investors of the opportunities that they can take advantage of, and the risks they face of being constrained off from the distribution network. For example, in an area that has a high penetration of roof-top solar systems, a consumer could decide to invest in batteries rather than solar panels, thereby supporting existing investments by their neighbours and also potentially taking advantage of an excess supply of cheap electricity in their area.

51 The availability of constraint information may also assist the AER if it chooses to provide incentives and disincentives for lower or higher levels of constraints respectively, and in assessing the merits of DNSP proposals to invest in mitigating constraints.

BOX 10: WORKING WITH CONSUMER GROUPS TO UNDERSTAND CONSUMER INFORMATION NEEDS

Information can benefit consumers by informing their decision making process. However, there appears to be limited understanding on the type and form of information that consumers would need to help them make decisions.

Not all consumers may want to receive all types of information or act on information available. There may be a role for third party providers in developing products or services to help remove complexity for consumers.

The Commission will work with consumer groups to improve its understanding of consumer information needs, and how third party providers could assist consumers acting on the information. It will also work with consumer groups to progress any regulatory changes, if required, to support the provision of relevant and appropriate information.

DNSPs' information challenge in a high DER world

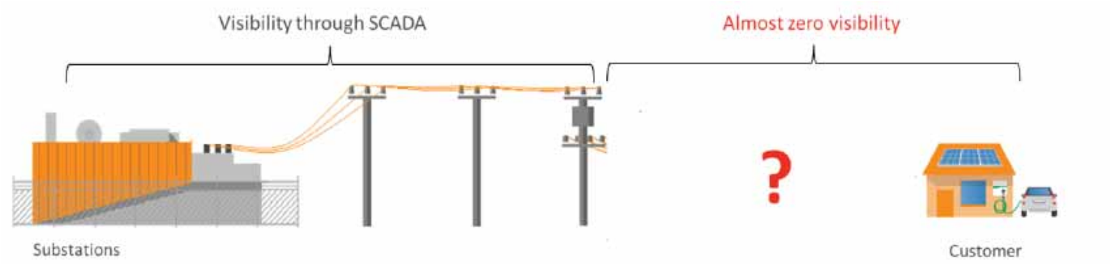
52 As discussed above, DNSPs will need to change the way they operate their networks in a high DER future. There are various strategies that DNSPs could implement to support the efficient integration of DER. However, the implementation of these strategies is often hampered by DNSPs' lack of visibility of their low voltage (LV) networks.

53 While DNSPs do have visibility over higher levels of their distribution networks through their supervisory control and data acquisition (SCADA) systems, they generally have limited visibility over their low voltage networks, which is where most DER constraints occur. The Commission conducted a survey of DNSPs' LV network visibility as part of the 2019 Review. The results of the survey reveal that:

- There is little direct monitoring of loads and voltages on LV transformers and circuits, and on individual phases of those circuits. Some of the monitoring that occurs is ad-hoc or alternatively measures only maximum load over a long period of time
- With the exception of Victoria, where meters are still owned and controlled by DNSPs, there is little information beyond settlement and billing data that is directly available to DNSPs at the customer premises level
- There is very little direct monitoring of DER generation output. Net metering arrangements mean that only the total site is monitored

54 The survey results also show that the challenge of LV networks visibility is common to many DNSPs, regardless of their DER penetration. The following diagram was presented by SA Power networks at the regulatory DEIP Dive, and it aptly illustrates the challenge.

Figure 2: DNSPs' LV networks visibility



Source: SA Power Networks, *Maximising customer value from the network in a high-DER future,* slides from AEMC/ARENA Regulatory DEIP dive, 6 June 2019, accessed via https://www.aemc.gov.au/sites/default/files/2019-06/ARENA%20AEMC%20DEIP%20Dive-%206%20June%202019%20-%20SAPN%20Presentation.pdf, slide 5

55 This limited visibility on the LV networks makes it difficult for DNSPs to operate their networks to support consumers' use of DER. In particular, the lack of information makes it difficult for DNSPs to determine where constraints exist or where they are likely to develop in the future. This in turn makes it difficult for a DNSP to find optimal solutions for alleviating these constraints.

Overcoming the information challenge

56 There are a number of ways in which DNSPs could improve their visibility of LV networks. Solutions to the problem range from installing monitoring devices, purchasing information from third party devices and/or smart meters and network modelling.

57 For example, as part of its 2020-25 regulatory proposal, SA Power Networks has proposed a sampling and modelling approach to managing the high levels of solar PV that currently exist (and are forecast to grow in the future) on its network. It combines modelling of its networks ability to host varying levels of DER with sample data on the real-time performance of its network from smart meter providers, inverters manufacturers and home energy management providers. This approach is detailed in a business case as part of its regulatory proposal, which is currently being considered by the AER.

BOX 11: DNSPS TO CONTINUE TO DEVELOP BUSINESS CASES FOR IMPROVEMENT IN LV NETWORKS VISIBILITY

Improving DNSPs' visibility of their LV networks is likely to require additional expenditure. The Commission considers that this expenditure is warranted where it is prudent and efficient.

The Commission encourages DNSPs to continue to develop business cases for improvement of modelling and monitoring of their LV networks, including the quantification of costs and benefits of their proposed approaches.

BOX 12: UNDERSTANDING FUTURE DATA REQUIREMENTS

In the future, DNSPs data requirements may evolve with changing DER technologies and the continual growth in DER uptake. The increasing penetration of DER may also create new system security challenges.

The Commission recommends that DNSPs, in collaboration with industry and consumer representatives, identify additional meter data that should be collected and made available in order to support LV network visibility, in a manner that maximises net benefits to consumers.

DER as part of an integrated, secure and reliable electricity system

58 DER plays an important role in a future electricity system. It is part of the broader change in generation mix where traditional synchronous (thermal) generation is replaced by asynchronous (variable renewable energy) generation. This change in generation mix brings challenges but also opportunities as essential system security services that were once provided as part of synchronous generation would now need to be procured.

59 The technical integration of DER is a key enabler to maximising benefits for all consumers. Programs such as ENA's harmonisation of LV connection standards and the update of AS4777 (inverter standards) are important foundational work to facilitate technical integration.

60 In the long term, the trend from centralised, synchronous generation such as large thermal power stations towards distributed asynchronous generation such as solar, wind and batteries may provide opportunities to operate and configure networks in entirely new, decentralised ways that take advantage of local energy sources in order to make electricity both cheaper and more reliable.[10]

61 Another important project aimed at efficiently integrating DER into the electricity system is the AEMO/ENA Open Energy Networks project (OpEN). OpEN has recently published its *Required capabilities and recommended actions report*, which 'outlines the key functions Australia's electricity system must have to ensure it operates safely and reliably, delivering benefits to all customers as it modernises to adapt to an increasingly renewable energy future'.[11] The Commission supports the work undertaken by OpEN and will continue to work with AEMO and ENA, who expect to finalise the project by the end of 2019.

BOX 13: DEVELOP TECHNICAL STANDARDS

A significant amount of work on technical integration of DER remains to be done.

The Commission supports AEMO's and Standards Australia's role in coordinating the industry's effort on technical integration, improving system resilience to disturbances, interoperability

10 See appendix E.

11 AEMO and Energy Networks Australia 2019, Interim Report: Required Capabilities and Recommended Actions, p. 1.

and emerging issues such as cyber security.

BOX 14: IMPROVE TECHNICAL COMPLIANCE

A number of stakeholders have expressed concerns regarding poor levels of DER compliance with existing installation and technical standards. The Commission recommends that jurisdictional governments and safety regulators consider mechanisms to assess the extent of non-compliance and improve compliance levels.

Working collaboratively with stakeholders

62 DER integration is not a task that can be achieved by one organisation or one part of the industry alone. The Commission acknowledges that all parts of the industry are working towards efficient DER integration. As discussed previously, jurisdictional governments, market bodies, consumer groups, standards organisations, industry bodies, businesses and researchers are all delivering programs of work that are important for the energy transition. No one body has all of the answers or can deliver all of the required outcomes. Success will rely on a shared vision and collaboration.

63 Under the DEIP banner, the Commission and ARENA jointly held a 'Regulatory DEIP Dive' workshop in June 2019 to explore how DNSPs will need to operate their networks differently in a high DER future and considered how networks should be regulated so that the overall costs of electricity supply are minimised. Participants at this workshop provided valuable insights on the challenges faced by customers and DNSPs as DER penetration increases and developed several reform ideas that will contribute to the goal of efficient DER integration for the benefit of all customers.

64 A key output from the Regulatory DEIP Dive was the creation of the DER Access and Pricing Working Group, where consumer representatives, ARENA, Energy Consumer Australia (ECA) and the Commission are working together to progress reforms relating to the distribution access, connections and charging framework. A number of workshops will be held in 2019, and it is expected that rule change requests recommending reforms will be lodged with the Commission by early 2020.

KEY RECOMMENDATIONS AND ACTIONS

Table 1: List of actions and recommendations

ITEM #	ACTION OR RECOMMENDATION	PARTY OR PARTIES
1	**Reforms to the distribution access and charging framework** Through the Distributed Energy Integration Program (DEIP), the Commission will work closely with stakeholders who intend to submit rule change requests to progress reforms to distribution access, connections and charging arrangements. If rule change requests on access and connection arrangements are not received by early 2020, then as part of the *2020 Economic regulatory framework review* (2020 Review), the Commission will consult on and develop detailed proposals for changes to distribution system access and connection arrangements to support consumers' needs while minimising total system costs.	AEMC, DEIP
2	**Development of a common value of customer export methodology** Through the DEIP DER valuation package of work, the Commission will work together with ARENA, AER, consumer groups and other stakeholders to develop a standard methodology to estimate value of customer export, which could be used to determine the value of a marginal increase in export hosting capacity.	AEMC, ARENA, AER, Consumer groups
3	**AER paper to provide guidance on efficient DER expenditure** The Commission supports the AER in developing a set of guidelines on how it intends to consider distributor DER integration expenditure in revenue proposals, as well as what it considers as prudent approaches in integrating DER. This guideline is due to be published in October 2019.	AER
4	**Continue implementation of network tariff reform** The Commission strongly supports the AER's contined effort to implement network pricing reforms through the TSS process and roundtables with stakeholders as an additional means to progress network tariff reforms.	AER
5	**Monitoring smart meter roll out**	AEMC

ITEM #	ACTION OR RECOMMENDATION	PARTY OR PARTIES
	Starting from the final quarter of 2019, the Commission will consult with industry to identify potential barriers to the roll out of smart meters and the use of smart meters to deliver the maximum possible benefits to customers. It will also commence gathering quarterly data from industry, AER and AEMO on the status of the roll out.	
6	**Review into competition in metering arrangements** The Commission committed to commence a review of competitive metering arrangements in December 2020, when it made the Competition in metering determination in November 2015. The Commission will commence this review as planned. The results of metering roll-out monitoring as recommend above, along with potential benefits of greater data collection and availability, would be significant issues to this review.	AEMC
7	**Working with consumer groups to understand consumer information needs** The Commission will work with consumer groups to improve its understanding of consumer information needs, and how third party providers could assist consumers acting on the information. It will also work with consumer groups to progress any regulatory changes, if required, to support the provision of relevant and appropriate information.	AEMC, Consumer groups
8	**DNSPs to continue to develop business cases for improvement in LV networks visibility** The Commission encourages DNSPs to continue to develop business cases for improvement of modelling and monitoring of their LV networks, including the quantification of costs and benefits of their proposed approaches.	DNSPs
9	**Understanding future data requirements** The Commission recommends that DNSPs, in collaboration with industry and consumer representatives, identify additional meter data that should be collected and made available in order to support LV network visibility, in a manner that maximises net benefits to consumers.	DNSPs, Consumer groups
10	**Develop technical standards** The Commission supports AEMO's and Standards Australia's role in coordinating the industry's effort on technical integration of	AEMO, Standards Australia

ITEM #	ACTION OR RECOMMENDATION	PARTY OR PARTIES
	DER, improving system resilience to disturbances, interoperability and emerging issues such as cyber security.	
11	**Improve technical compliance** A number of stakeholders have expressed concerns regarding poor levels of DER compliance with existing installation and technical standards. The Commission recommends that jurisdictional governments and safety regulators consider mechanisms to assess the extent of non-compliance and improve compliance levels.	Jurisdictional governments and safety regulators

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1 A DYNAMIC AND CUSTOMER-CENTRIC ELECTRICITY SYSTEM

The Commission's vision for the future electricity system is one of two-way trade of electricity and services in a wholly connected energy market. If effectively integrated into the grid, the increasing proportion of grid scale and distributed renewable generation can put downward pressure on wholesale energy costs. Energy services in the future will be able to be bought and sold in a dynamic way, responding to consumer preferences and price signals. New technology such as battery storage and electric vehicles (EV) will bring different dimensions to electricity system usage. The electricity network is becoming a trading platform, and consumers are becoming the drivers of change. As technology improves and becomes cheaper and more accessible, and appropriate consumer protections are developed, services such as network support and demand response may no longer be restricted to large customers. Distributed energy resources (DER) play an important role in this future.

DER will enable customers to take advantage of, and benefit from, the changes in the electricity system. Some customers[12] could use their DER to help lower their electricity costs, while others with controllable DER such as batteries may want to actively inject stored surplus electricity back to the grid. Some may wish to participate in the new energy markets and provide services such as demand response or services that support overall system security. Customers who do not wish to, or may not have the capacity to, access DER will still benefit from lower total system costs and improved reliability and security.

DER customers will not have to navigate the new electricity system on their own. Decisions about what to invest in and how to get the most value out of their investment could be passed on to an agent – such as their electricity retailer or an energy services company – to optimise DER services on their behalf.[13] These agents may also be able to create additional value for customers through aggregation.

1.1 Optimising the benefits of DER for all Australians

DER needs to be integrated into the electricity system for the benefit of all Australians, regardless of whether they have access to solar panels or not.

DER is a flexible resource from both a load and generation perspective. Generation assets (such as solar PV and batteries) could provide low cost energy,[14] as well as ancillary services in competition with traditional providers. Devices or programs that promote and enable load flexibility could help deliver more efficient use of existing network infrastructure. Effectively integrated DER can also provide services that support the reliability and security of the system, helping the Australian Energy Market Operator (AEMO) and network businesses maintain a reliable and secure system at a lower cost.

12 For example, those who have solar PV systems only.

13 The Commission's *2019 Retail Competition Review ,* published in June 2019, discussed a number of emerging models where consumers can choose to let their DER be aggregated into a virtual power plant. These options include retailer-led aggregation of DER, retailer and independent battery service provider coordination of DER, and battery service provider-led DER aggregation.

14 DER such as roof top solar system can generate electricity at zero marginal costs when the sun is shining.

The potential benefits of efficiently integrated DER for all consumers are substantial and the timely development of a supportive regulatory framework is essential. Conversely, consumers will bear the costs if DER is not integrated into the electricity system efficiently. A regime that does not provide consumers with choice and reward supportive behaviours could drive up costs. Electric vehicles could add to peak demand instead of smoothing it, zero marginal cost solar generation could be unnecessarily constrained off, prices could become more volatile instead of less, and consumers could be driven into supply arrangements where developers or local monopolies control their supply and appropriate their DER benefits.

1.2 The 2019 Economic regulatory framework review – identifying actions and reforms

Actions and regulatory reforms are required in order to optimise the benefits of DER for all electricity system users. A substantial work program is already underway through market institutions,[15] consumer groups, regulated network businesses and government agencies. In this *2019 Economic regulatory framework review* (2019 Review),[16] the Commission seeks to place this important and necessary work within the overall context of the required regulatory framework and identify gaps where actions and/or reforms are needed. Through this review, the Commission also monitors developments and considers potential improvements to regulatory and energy market arrangements.

The actions and reforms that the Commission has identified in the 2019 Review are described briefly below.

1.2.1 Rewarding customers for better utilising the network – Chapter 2

Pricing is one of a number of 'tools' that can be used to optimise the benefits of DER for the Australian community. This chapter discusses how network services can be priced to send efficient signals to whoever has control of DER, to provide the service that will deliver the most value at that point in time.

Historically, network prices were used to signal to the customer the impact their electricity consumption (i.e. electricity import) has on current and future network costs. The role of network prices will need to evolve as customers' use of the electricity system changes with the increasing uptake of DER.

There are two key issues that need to be addressed to support the future customer-centric electricity system and the provision of new electricity services. First, some consumer representatives have raised concerns about the potential for current consumption-only charging arrangements to create inequitable outcomes for customers who do not have access

15 Market institutions include: the Energy Security Board (ESB), the Australian Energy market Commission (AEMC), the Australian Energy Regulator (AER), and the Australian Energy Market Operator (AEMO).

16 The 2019 Review is an annual review of the economic regulatory framework for electricity networks, and is a key part of the Commission's work to support the ongoing evolution of the energy sector. In light of the significant growth in DER, the review examines whether the economic regulatory framework is sufficiently robust and flexible and continues to support the efficient operation of the energy market in the long term interest of consumers. It is conducted under a standing terms of reference provided by the Council of Australian Government (COAG) Energy Council. The first report of this review was published in 2017.

to DER. The networks charging arrangement could be changed to reward DER customers for their investments, while not creating disadvantages for non-solar PV households.

Second, flat pricing options are unsustainable in a future DER world. In particular, the emergence of EVs could exacerbate peak demand and increase the need for additional network investment. Flexible tariffs could incentivise customers to charge their batteries or electric vehicles at times when the system is least congested, or when there is an abundance of low cost energy – such as distributed solar generation.

The Commission has been collaborating with energy sector stakeholders, including through workshops and working groups, to lay the foundation for potentially significant reforms to network charging arrangements.

1.2.2 Options to facilitate greater access to the grid for distributed energy resources – Chapter 3

Changes to distribution charging arrangements cannot be considered as a stand-alone issue as they have flow on implications to the distribution access and connections framework. Chapter 3 examines risks that are emerging under the current open access framework and considers the suitability of the range of actions that DNSPs could undertake to facilitate the integration of increasing levels of DER.

In the long term, reforms to the access framework are required to provide additional tools to optimise the provision of DER services. Some potential reforms options include allowing customers to select varying levels of static export limits and choose different levels of firmness. As reforms to access, connections and charging arrangements are inherently complex, the Commission is committed to working with stakeholders to consider reform options and progress relevant rule change requests.

1.2.3 Information to support decision making in a smart grid – Chapter 4

Information availability, both to customers and DNSPs, is a key enabler for the efficient integration of DER. Information allows DNSPs and consumers to make informed choices about how to best utilise DER and manage network constraints and technical issues at the lowest cost. For example, the current lack of information on the low voltage (LV) networks is hampering DNSPs' ability to integrate higher levels of DER.

Some relevant information could be made available at low cost. Other information may be highly beneficial to decision making but is costly. This chapter identifies key sources of information, how it can be provided in a cost effective way, and by whom.

1.2.4 Maintaining security and reliability of the network – Chapter 5

Any future electricity system, regardless of its generation mix, will need to continue to provide secure and reliable electricity supply to customers. As DER penetration increases it can impact the way that the electricity supply system behaves. To maximise the value of DER, it should behave predictably and, where possible, actively support system security and reliability outcomes.

This chapter discusses issues that, if not addressed, may constrain the degree to which DER can participate in the provision of services to the broader electricity supply system. It discusses key considerations such as predictability of performance, the importance of common standards and interoperability, DER's impact on system stability and the work on technical integration that is currently underway.

1.2.5 Consumer engagement – Chapter 6

Consumer choices about how and when to consume and export electricity should drive the transformation of the energy sector. It is therefore increasingly necessary for networks to understand and reflect consumer views, preferences and priorities in their regulatory proposals. Early and meaningful consumer engagement is important now more than ever.

The Commission has been monitoring consumer engagement developments, especially since reforms made in 2012 to require network businesses to better engage with consumers. For this year's report, the Commission has reviewed the progress of DNSPs in developing their consumer engagement approaches and, more broadly, the degree of cultural change in the sector to date. This informs the extent to which networks will be adaptable to transition to a more consumer-centric and wholly integrated energy market.

1.2.6 Ongoing monitoring of robustness of regulatory framework – Chapter 7

The Commission's role as part of the Economic regulatory framework review is to consider the flexibility of network regulation to support the ongoing transformation of the energy market. The Commission continues to develop its views on future options for network regulation reform more broadly. One such issue is the risk of inefficient investment caused by unbalanced incentives, which may undermine the development of the future energy market.

This chapter discusses the outcomes of the Commission's consultation on alternative models of network service providers' expenditure assessment and remuneration. This addresses one of the recommendations from the Independent Review into the Future Security of the National Electricity Market (the Finkel Review).

1.3 Working collaboratively with stakeholders

DER integration is not a task that can be achieved by one organisation or one part of the industry alone. The Commission acknowledges that all parts of the industry are working towards efficient DER integration through a number of work programs. Jurisdictional governments, market institution, consumer groups, standards organisations, industry bodies, businesses and researchers are all delivering programs of work that are important for the energy transition. No one body has all of the answers or can deliver all of the required outcomes. Success will rely on a shared vision and collaboration.

The Commission has consulted widely to understand the nature and magnitude of the DER integration issues and the different work programs that aim to address various aspects of the integration. Commission staff also worked closely with consumer groups through the National Consumer Roundtable on Energy to consider DER integration from a consumer centric perspective.

The Commission is committed to working with stakeholders towards the goal of optimising the benefits of DER for the benefit of all electricity system users. In this review the Commission has worked collaboratively with a broad range of stakeholders through the Distributed Energy Integration Program (DEIP). An ARENA-led initiative, DEIP is a collaboration of government agencies, market authorities, industry and consumer associations aimed at maximising the value of customers' DER for all energy users.

Under the DEIP banner, the Commission and ARENA jointly held a 'Regulatory DEIP Dive' workshop in June 2019 to explore how DNSPs will need to operate their networks in a high DER future and considered how networks should be regulated so that the overall costs of electricity supply are minimised. Participants at this workshop provided valuable insights on the challenges faced by customers and DNSPs as DER penetration increases, and developed several reform ideas that will contribute to the goal of efficient DER integration for the benefit of all customers.

A key output from the Regulatory DEIP Dive was the creation of the DER Access and Pricing Working Group, where consumer representatives, ARENA, Energy Consumer Australia (ECA) and the Commission are working together to progress reforms relating to the distribution access, connections and charging framework. A number of workshops will be held in 2019 and early 2020, and it is expected that rule change requests recommending reforms will be lodged with the Commission by the end of the first quarter of 2020.

2 REWARDING CUSTOMERS FOR BETTER UTILISING THE ELECTRICITY NETWORK THROUGH PRICING

Dynamic pricing signals have the ability to provide all customers with lower bills as DER drives lower total system costs. Customers can access lower price periods if they are able to respond to price signals.

Dynamic pricing signals also increase prospective returns on customer DER investments and provide customers with greater choice, including on their emissions intensity preferences.

DER can help to smooth the demand profile of the grid and thereby increase utilisation of network infrastructure, resulting in a more productive and efficient power system to the benefit of customers. In the absence of dynamic pricing signals DER can also do the reverse, increasing peakiness and driving up electricity costs.

The way customers interact with the energy system and pay for electricity is gradually changing in response to new technology and market developments. Most customers continue to rely on the grid for their electricity supply and pay flat rates. An increasing number of households have invested in DER generation and sell their excess energy production back into the grid based on flat rate or time-varying feed-in tariffs. Going forward, DER could be used to provide new and innovative services, providing competition to traditional large-scale generation for both energy and system support services.

Optimising the provision of multiple DER services maximises the benefits of DER for the broader community. This optimisation requires signals to whoever has control of DER to provide the service that will deliver the most value at that point in time or, if possible, to store energy to provide services at a different time.

DER exporting into the grid can also create new challenges. Reverse power flows can create voltage fluctuations, which distribution businesses are responsible for managing within regulated standards. Local networks also have physical limits on the amount of DER they can host. Further, high solar PV output has significantly reduced demand in the middle of the day, which has implications for how networks recover costs and how those costs are shared among solar PV and non-solar PV households.

The likely uptake of electric vehicles (EVs) creates the opportunity to significantly increase utilisation of the grid. It is widely acknowledged that energy policy needs to get ahead of this issue so that EVs do not overload the electricity system at times of peak demand – which could otherwise result in significant grid instability and expensive network augmentation.

To optimise DER and manage these challenges, signals to customers can be provided through more dynamic electricity prices for both exporting into and importing from the grid, and for system and network support services, to incentivise efficient allocation of resources. This chapter explains how efficient pricing could work to the benefit of customers, highlights the wider implications of different pricing arrangements for the energy regulatory framework, and describes progress on related reforms and what further actions can be taken.

The Commission has been working closely with energy sector stakeholders on these issues, including through workshops and working groups. In particular, through the Distributed Energy Integration Program (DEIP), the Commission has been collaborating with a broad range of stakeholders, including consumer representatives, to identify issues and lay the foundation for potentially significant reforms to improve signals for use of DER in the energy system.

2.1 Maximising the community benefits of DER exports

DER allows customers to generate and store electricity and export it into the grid. Consumers currently receive feed-in tariffs that are generally based on forecast generation costs – which are avoided by DER.[17] Customers can also now participate in the wholesale energy market and support services markets, such as the frequency control ancillary services (FCAS) market, through aggregators and virtual power generation platforms that provide greater scale. New services could form the basis for emerging DER markets, such as voltage control and reactive power services, 'ramping' and demand response.[18] DER can be used to defer the need for network augmentation by supplying local needs.[19]

These DER services will potentially have different market values at different times and locations depending on demand and supply balances and any constraints – for example:

- when there is an abundance of low cost generation and low levels of demand, such as times of high solar output, the value of electricity exports will be lower
  - these are the times when DER (specifically, storage technologies) can potentially be better used to soak up excess solar PV generation, including through household or community batteries, or hot water systems
- at periods of high demand, the value of electricity exports will be higher
  - waiting to discharge stored electricity at these times would maximise the value of DER by, for example, creating a competitive constraint on the wholesale market or by reducing the need for network augmentation
- if a system event, such as a generator or transmission feeder trip, causes an energy imbalance, then DER can respond to keep the supply system stable
- if local voltage is nearing allowed limits then DER inverters can respond to help maintain supply within regulated voltage limits.

Where constraints exist, then optimal allocation of DER services requires there to be no other use that would yield a higher value or net benefit. Allocative efficiency is about ensuring that the community broadly gets the greatest return from its scarce resources.

17 In some states, DER participants may receive a premium feed-in-tariff that is paid by the distributor and its cost recovered from all customers.

18 The COAG Energy Council in December 2018 agreed to draft a regulation impact statement (RIS) for certain electrical appliances to be demand response capable. It is proposed that all air conditioners, electric storage water heaters, pool pump controllers and electric vehicle (EV) chargers that are supplied or offered for supply would have to comply with the full range of demand response modes in either the relevant part of AS/NZS 4755 Part 3 or AS 5755.2. (See: http://energyrating.gov.au/consultation/consultation-smart-demand-response-capabilities-selected-appliances viewed 4 September 2019).

19 There may be other system-wide benefits provided by DER that are not currently recognised.

This is an area where the AEMO and ENA Open Energy Networks project can make a valuable contribution. It is looking into the future to consider how a system operator can play a role in the optimal use of DER so multiple possible services are allocated to the highest value use at any given point in time.

Household supply-side solutions will also help to integrate DER into the energy system and efficiently allocate resources. Consumers will be able to employ automated technologies, retailers or new service providers to optimise DER on their behalf (section 2.1.1). Smart home energy management systems are emerging that are capable of controlling household load in response to signals from energy service providers. In the future, it is expected that an aggregator could facilitate negotiations between the customer and the distributor on the services to be provided and associated payments for those services, reducing complexity for consumers.

Prices received for outputs *and* costs paid for inputs are both factors that guide the allocation of resources. The distribution system needs to accommodate forward and reverse power flows that can fluctuate significantly throughout the day. This can impact the quality and reliability of power supplies at certain times, especially during periods of very high or low levels of demand. Networks incur costs to manage these issues. This is a cost of DER services and should be factored into DER investment decisions to achieve the most efficient allocation of resources – consistent with competitive markets throughout the economy.

Tariffs for network services could be used to better signal the input costs for providing those services as well as the value of those services (section 2.1.2), and signalling the need for additional network investment where appropriate. Otherwise, consumers may become increasingly frustrated by DER connection, curtailment, or voltage issues that impact the financial return on their DER investment.

2.1.1 New supply-side solutions to manage added energy market complexity

Future technology developments, as well as wider uptake of existing control technologies, will enable demand-side participation without the need for manual intervention – minimising the impact on consumers. Automated technologies, retailers and third party service providers are expected to be able to help consumers respond to dynamic pricing signals, shifting their use away from high demand periods to when power is available at a lower cost. Manually optimising provision of DER services is expected to be otherwise too complex for small customers.

For example, affordable automated home energy management systems with 'set-it, forget-it' technologies could someday allow consumers or their service providers to pre-program use-parameters, with minimal negative impact on their economic activity. Home energy systems and connected DER are expected to be able to respond to more complex and reflective price signals. Network tariffs could be designed for smart energy systems to provide significantly improved cost reflectivity as well as bypassing the risk-aversion that many consumers have to complex tariffs.[20] An alternative paradigm is electricity providers delivering services through

20 https://www.linkedin.com/pulse/machine-electricity-tariffs-who-first-anthony-seipolt viewed 4 September 2019.

subscription agreements, with tiered price contracts that allow consumers to choose parameters but leave control to electricity providers.

Even now, new equipment, appliances and software are available that use emerging smart grid technologies to save energy and seek out the lowest rates. Specific loads such as electric hot water, pool pumps and air conditioners can be controlled remotely to reduce costs without impacting consumers. These trends will be accelerated by the entrance of new services providers marketing home energy management services.

To optimise benefits to consumers, smart home energy management systems need to have access to real time information on network constraints and dynamic operating envelopes, as well as price signals at the wholesale level. Chapter 4 of this report also discusses the information requirements for consumers and DNSPs in a high DER future.

Distributors, retailers and third party providers could work together to undertake consumer 'automation trials', where customers with DER test 'set and forget' home energy management systems. Such trials could help estimate potential system-wide benefits from DER services and to mitigate consumer concerns about being exposed to dynamic signals – such as the risk of bill shock and negative impacts on economic activity.

2.1.2 Moving away from consumption-based charging

Network charges for the use of the 'poles and wires' to transport electricity to meet household demand only apply to imports (i.e. energy consumed by the customer). They do not apply to electricity exports into the grid from DER.

Clause 6.1.4 of the NER provides that a distribution network service provider must not charge for the use of the system for the export of electricity generated by the user into the distribution network. This does not, however, preclude charges for the provision of connection services.[21]

As solar penetration increases to levels that cause network constraints, distributors have the options to either constrain exports or build out the network.[22] The capital and operating costs of building and maintaining the network, as well as any difference between connection costs and connection charges, are recovered from all consumers through consumption charges.

Some consumer groups have expressed concerns that the current charging arrangements – where the cost of the distribution network is recovered solely through consumption charges – are leading to inequitable outcomes, with the cost of DER integration being borne by consumers regardless of whether they own DER. They are concerned that customers who do

21 These charging arrangements were designed to provide competitive neutrality with large transmission connected generators. There was also a view that a range of incentive and information asymmetry issues existed that may have impeded the efficient negotiation of distributed generation connection charges. See Standing Committee of Officials of the Ministerial Council on Energy, NERA Economic Consulting Review of network incentives for Distributed Generation and Demand Side Response, April 2007, pp.5-6; and NERA Economic Consulting, Part One: Distribution Rules Review – Network Incentives for Demand Side Response and Distributed Generation, April 2007, pp. 64-66.

22 Customers could be offered alternative options for connection when there are network constraints, such as partial or full export limitations, spreading connections evenly across three phases, leveraging reactive power control functionality in inverters, or performing connection augmentation – in which case the customer may be required to pay a capital contribution towards augmentation costs. (AEMC, Distribution Market Model, Final report, August 2017, p. 61.)

not have or cannot access DER do not have any means to mitigate any additional network expenditure to facilitate additional DER exports.

The Commission previously found an obligation on the distributor to build out constraints to accommodate this additional generation may not be fair or efficient because the costs would be shared by all parties, but the benefits would only be captured by those with DER. There is also not a strong incentive for the owner of the DER to pay to build out the constraint, as there may be a risk that others would connect and constrain the network again, with no means for the owner to manage the risk (unlike large-scale generation, which can manage this risk through offering into the wholesale market).[23]

Inequitable outcomes can also arise from distributors taking a 'first in, best dressed' approach to DER connections – especially in relation to the consumer's ability (or restrictions on their ability) to inject energy to the grid. The Commission understands that in many network areas consumers who were early DER adopters are able to export energy into the grid with high export limits (e.g. 10 kW). However, as DER uptake increases and technical issues such as voltage limits are reached, new DER installations receive either a very low or zero export limit.

The Commission maintains that static export limits on export are a blunt approach to addressing the impact of DER on the network. Restricting export is unlikely to be efficient or meet consumers' expectations. Where this restriction applies only to consumers who are connecting to the network at a later time, this raises issues of equity and is likely to be inconsistent with the 'open access' nature of the regulatory regime.[24]

The St Vincent de Paul Society Victoria considers the NER should ensure that the direct beneficiaries of DER also directly contribute to network upgrades required to deliver these benefits:[25]

> The Rules should enable a pricing framework that delivers equitable outcomes for various customer groups, promotes the uptake of DER, and encourages the release of new technologies and services to support consumer decisions and choices in the energy market as it evolves.

St Vincent de Paul Society Victoria proposes two options to enable DER participants to contribute to network costs: (1) allow distribution businesses to charge DER participants for using the network by amending clause 6.1.4 of the NER or (2) reflect the cost of exports to the network in the feed-in-tariff. It states:[26]

> If the networks were required to charge DER participants a charge per kWh for DER exported back via the grid, this revenue could be used to upgrade networks to limit constraints and enable future DER penetration.

23 AEMC, Distribution Market Model, Final report, August 2017, p. 60.
24 AEMC, 2018 Economic regulatory framework review, July 2018, p. xi.
25 St Vincent de Paul Society, Options for an equitable DER future: A Discussion Paper, August 2019, p. 6.
26 St Vincent de Paul Society, Options for an equitable DER future: A Discussion Paper, August 2019, p. 11.

> Importantly, we are not necessarily advocating for an approach where DER participants have to pay for using the networks. Rather we are proposing to explore a solution that allows DER generators to choose between paying or being constrained. This is an important distinction as some DER participants may prefer being constrained rather than paying a DUOS charge for export.

The Commission is working closely on these issues with St Vincent de Paul Society Victoria and the DEIP DER Access and Pricing Working Group.[27] This working group seeks to determine how the economic regulatory framework should evolve to meet user expectations, which are changing as we move to higher penetration of DER. The aim is to build consensus on equitable and efficient DER access and pricing models, supported by clearly defined customer centric market design principles and momentum for the changes. This working group intends to develop a rule change request to reform the networks charging arrangement in light of the changing interaction between consumers and the electricity system.

Impact of charging reforms on other areas of framework

Changes to distributor charging arrangements to reflect their evolving role cannot be considered alone and these changes need to be part of a broader assessment of the regulatory framework. For example, permitting distributors to apply use-of-system charges on generators would require consideration of at least the following areas:

- Level and types of services provided by distributors – export charging is inconsistent with the current open access framework where generators do not pay for the use of the network, but do not receive guaranteed access. If generators are required to pay for the use of the network to export energy, consideration would need to be given the level of services that they would receive in return for payment.
- Access arrangements – related to the above, distributors will also need to consider how pricing might interact with the firmness of generator access. They may also need to consider how DER will need to be curtailed if the network is constrained as a result of DER exports. Chapter 3 of this report discusses reforms to the access framework in further detail.

More broadly, reforms to charging and access arrangements as well as the changing nature of distribution services, are likely to have flow on effects on the revenue building blocks for expenditure. The NER require the AER to use the building blocks approach to determine how much revenue a network business needs to cover its 'efficient costs' over the coming regulatory period. The AER uses the building blocks approach to forecast and lock-in the total revenue that an efficient and prudent business would require. In doing so, the AER takes into account expected demand and cost inputs, all applicable regulatory obligations or requirements on the business, and the reliability, security and safety of the network (among other things).[28] There may be additional costs for distributors to meet new obligations and

27 This working group comprises representatives from ACOSS, AEMC, ARENA, ECA and the Total Environmental Centre (TEC).
28 See NER, Part C of Chapter 6.

allocate allowed revenue so that network pricing structures balance both import and export network charges.

2.2 Minimising the costs of importing electricity from the grid

Consumers will continue to rely on the grid to import electricity, including for charging their batteries and electric vehicles.

Under traditional network tariff structures, households pay the same prices regardless of how and when they use energy. Network charges for smaller consumers have historically been levied on the basis of energy consumption (i.e. $/kWh).

To reward customers for actions that better utilise the network or improve reliability, charges paid by a network user should ideally reflect the impact the user has on current and future network costs, as well as the cost of generating the electricity. Cost reflective network pricing could help to achieve this objective by providing more accurate price signals, improving incentives on consumers to adjust their use of the network and consumption of electricity (section 2.2.1).

Given excess capacity in many parts of the system due to falling or relatively flat demand, some stakeholders question the ongoing need for cost reflective tariffs. But dynamic pricing is also an important way to optimise DER services to facilitate better use of the network. There is a high risk that consumers will need to fund major network build to cope with increased uptake of solar PV and electric vehicles, if consumers are not rewarded for using these resources more efficiently (section 2.2.2).

2.2.1 Flexible pricing options to reward consumers

Cost reflective prices can reward consumers for using electricity outside of peak hours, investing in smart appliances or using their DER to generate energy at peak times. It provides customers with increased control over their bill, and creates opportunities for significant savings to individual households, and improved reliability and security.

There are multiple ways in which consumers could pay for services that may be offered by distributors in the future. Pricing options need not be based on the traditional volumetric (e.g. c/kWh) charges and could entail a combination of fixed connection charges, capacity payments as well as (potentially time varying) volumetric payments.

Some networks such as Energy Queensland have also considered applying the concept of 'subscription + top up' where a consumer would pay a regular subscription for an agreed base level of capacity and pay for 'top ups' should they consume or export more than their base subscription level. It may also be appropriate for charging to be agnostic to whether the network is used for export or consumption – for example, you pay per kWh for your combined import and export.

A further potential element of tariff reform is the extent to which network tariffs vary by location. A network's costs and available capacity are not consistent across the network. The cost differences may be ongoing (such as for rural parts of the network) or temporary (where part of the network is constrained and so requires augmentation without some form of demand response).

Progress on tariff reforms

The requirement for distributors to develop cost reflective network prices was introduced by the Commission's Distribution network pricing arrangement rule change in 2014.[29] This rule change also requires distributors to develop a tariff structure statement (TSS) that outlines the proposed pricing structure for the next regulatory period – which the AER examines within the revenue allowance determination process. The regulatory framework prevents distributors increasing the total amount of revenue they recover from consumers. So any increase in one part of a tariff is offset by a reduction in other parts of the tariff.

Retailers pay the new network charges initially, then decide how to recover these costs and their other costs as part of their overall retail charges to consumers. Retailers are currently free to manage network price signals according to their individual market strategies. There is no reason why retailers need to 'pass on' network charges by structuring retail prices to match network prices or tariff structures, just as in most cases they currently do not pass on wholesale prices that can vary every 30 minutes.

To balance efficiency considerations and the customer impact principles, the AER is using an iterative approach to TSS assessments, with measured but consistent progress across multiple five-year regulatory periods. The pace of progress is heavily informed by expressed customer preferences, customer impacts, as well as the roll out of advanced metering infrastructure ('smart meters').

The first TSS period saw distributors gradually shift their tariff structures away from consumption-based and declining block tariffs – but generally on an 'opt-in' basis, which has led to a slow uptake of cost reflective tariffs so far. The Commission observes retailers rarely offer products for customers to passively (e.g. load control) or actively (e.g. demand response) respond to these signals.

More recently, distributors have stepped up their plans – moving to opt-out assignment of cost reflective network tariffs and promoting cost reflective choices with options to use time of use and/or demand structures. Further, anecdotally, retailers are beginning to consider how they could manage or re-package the cost reflective network tariffs for their customers.

In April 2019, the AER approved tariff structure statements for electricity distribution businesses in the Australian Capital Territory, New South Wales, the Northern Territory and Tasmania (six distribution businesses in all). These decisions have determined how network tariff reform will progress in these networks until 2024. The AER estimates up to half of the customers in these networks will be assigned to cost reflective network tariffs by 2024, with this outcome linked to the rate at which smart meters are installed for new connections, changing connections or to replace failed meters.

29 AEMC, Distribution Network Pricing Arrangements, https://www.aemc.gov.au/rule-changes/distribution-network-pricingarrangements

Draft determinations are currently being developed for the South Australian and Queensland distribution networks. The five Victorian distribution businesses will submit proposals in early 2020.

Energy sector collaboration to progress tariff reform

At the December 2018 COAG Energy Council meeting, Ministers agreed to request the AER, supported by Energy Consumers Australia, to report on progress with the transition to cost reflective network pricing.

The AER has held several roundtables with participants across the supply chain, consumer groups, and market bodies, to develop consistent national strategies and principles to pursue tariff reform and facilitate more coherent collaboration between key stakeholders. In particular, these roundtables are improving communication between the distributors and retailers to progress tariff reforms. The AER and ECA have been engaging with numerous stakeholders to explore the practicalities of tariff reform and interactions with other developments.

There has been a greater emphasis on communicating how more dynamic network tariff structures can reward consumers for utilising the network and their DER in ways that minimise system-wide costs for the whole community. To support a recent AER roundtable, ENA engaged Cambridge Economic Policy Associates to provide advice on sector-wide measures to push forward on tariff reform, including a communication campaign to inform consumers of how the changes can impact and benefit them.[30] Another recent initiative is the Future Grid Homes project, which aims to identify best practice household engagement for the future grid. The purpose of this engagement is to improve households' trust, participation in demand management, and adoption of DER intended to support affordability and reliability objectives for residential energy consumers.[31]

The Commission strongly supports the AER's continued effort to implement network pricing reforms through the TSS process and roundtables with stakeholders as an additional means to progress network tariff reforms.

2.2.2 Flat pricing options are unsustainable in a future DER world

Increased penetration of DER investment and concerns about efficient and equitable recovery of network costs from households with and without DER are creating new challenges.

Growth in solar PV has resulted in a greater number of households exporting to the grid, especially during the middle of the day when the sun is at its highest point. The high penetration of DER and air-conditioning, combined, has contributed to falling electricity consumption but without as large a fall in peak demand – reducing utilisation of the network. Also, the emergence of EVs could exacerbate peak demand and increase required investment costs, if consumers are not incentivised to charge their cars during off-peak periods.

30 CEPA, Achieving network pricing reform: Lessons from other jurisdictions and sectors, September 2019.

31 Emerging Technologies Research Lab (Monash University) and Centre for Urban Research (RMIT University), Engaging households towards the Future Grid: an engagement strategy for the energy sector, 2019, p. 8.

Flat tariff structures are not able to signal the cost impact of usage patterns to consumers, especially during periods of very high or low levels of demand. This means that customers who use the same network capacity, and therefore impose similar costs on the network, may bear very different proportions of network costs. This creates inequity in the allocation of network costs, which will be borne disproportionately by those customers unable to access DER. At the extreme, inefficient signals under flat tariff structures may see some customers deciding to completely disconnect from the grid despite the cost of self-supply being higher than the cost to the distributor of supplying them through the grid – putting more pressure on costs for those remaining on the grid.[32]

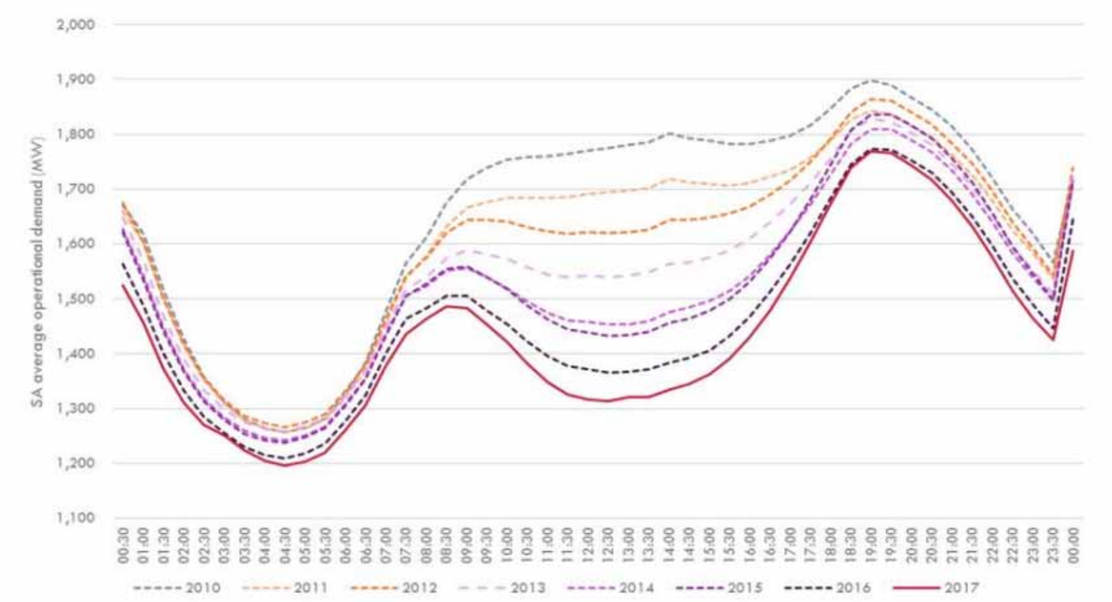
The 'duck curve' issue

Steady regulated asset bases coupled with falling rates of return, driven in large part by falling interest rates, is leading to reduced revenue allowances for network businesses. However, this is not necessarily flowing through to lower network prices for consumers. Some consumers with solar panels are meeting some or all of their own daytime power needs through self-generation, reducing the total amount of electricity consumption that is drawn through the networks, but still using the grid at night.

This hollowing out of demand through daylight hours is often referred to as the 'duck curve', whereby electricity consumption from solar PV households especially decreases in the middle of the day, but there is little impact on evening peak demand. This is illustrated below for South Australia. The total energy consumed is represented by the area under the curve, which is falling over time.

32 ACCC, Retail Electricity Pricing Inquiry: Final Report, June 2018, p. 179.

Figure 2.1: Effect of growing rooftop solar



Source: AEMO, *AEMO observations: Operational and market challenges to reliability and security in the NEM*, March 2018, p. 7
Note: This figure shows average operational demand in South Australia. These trends are emerging in other NEM regions

To maintain their revenue requirements, network businesses may have to increase unit prices to compensate for falling energy consumption. Network charges per kWh of energy delivered are increasing in some network areas. In South Australian network tariffs rose by over 10 per cent for the 2019-20 financial year, despite allowed revenue rising by only 4 per cent.[33] In this context, government policies to promote behind the meter solar PV may be indirectly contributing to higher network prices. Cost reflective pricing can reward consumers for utilising the network and their DER in ways that minimise system-wide costs so that non-solar PV households can also share in the benefits of DER.

Electric vehicles

The Electricity Network Transformation Roadmap, prepared by the CSIRO and ENA in 2017, examined the effect of EV adoption on the electricity sector under two scenarios: (1) slow change to electricity pricing and incentives, and (2) faster reform of pricing and incentives. In both scenarios, the Electricity Network Transformation Roadmap projected additional national electricity consumption from electric vehicles to be 5 TWh of electricity in 2027 and 43 TWh by 2050.[34]

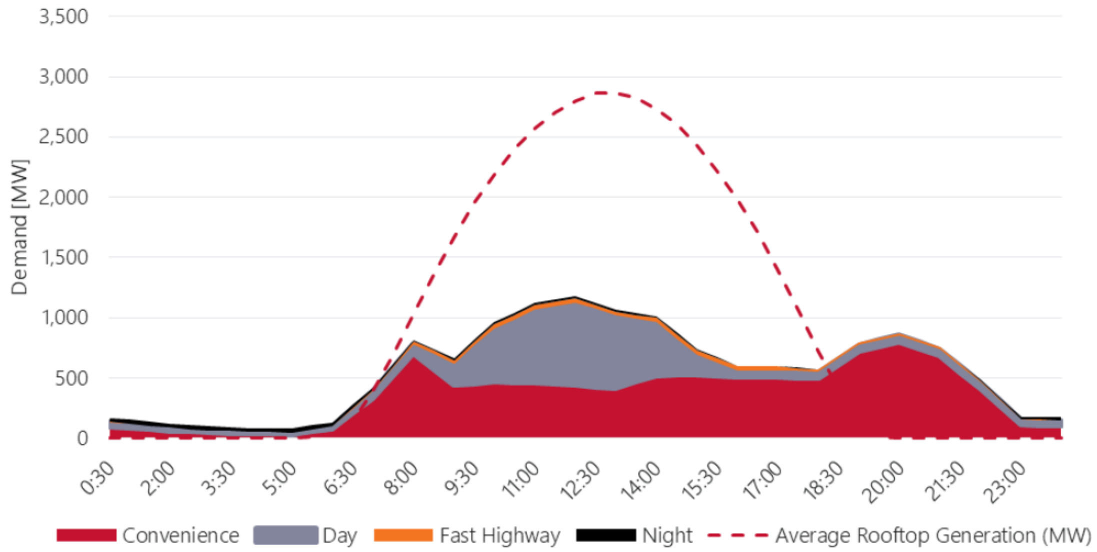
The Electricity Network Transformation Roadmap found that while reformed pricing and incentives minimise the impact of electric vehicle adoption on peak demand by encouraging managed charging, slower pricing and incentives reform adds an additional 12,000 MW of

33 See: https://www.aer.gov.au/communication/aer-approves-2019-20-network-tariffs-for-sa-power-networks
34 CSIRO and ENA, Electricity Network Transformation Roadmap: Final Report, April 2017, p. 34.

aggregate non-coincident zone substation load nationally by 2050 due to a higher degree of unmanaged charging.[35] These results appear to be largely consistent with overseas studies.[36]

AEMO considered the impact of EVs on the daily load profile and maximum demand depends on how and when they are charged.[37] AEMO modelled how higher uptake of EVs with 'convenience charging'[38] may add to peak residential demand, as shown in the figure below.

Figure 2.2: Average weekday EV demand by charge profile type assumed for the Central scenario in January 2039 in New South Wales



Source: AEMO, 2019 Electricity Statement of Opportunities, August 2019, pp. 40–41.
Note: Motorcycles are not shown in the charging profile, as their assumed electricity consumption is less than 0.5% of residential cars.

Andrew Dillon, CEO of ENA, highlighted the risk of increasing peak load:[39]

> A 'dumb' energy future, where there is high use of storage devices (which includes electric vehicles) but limited visibility of when batteries are charging and discharging, is one of unreliable power supply. Multiple batteries discharging into the system at once could cause a local system to trip off due to voltage or frequency problems, resulting in localised power outages.

35 CSIRO and ENA, Electricity Network Transformation Roadmap: Final Report, April 2017, p. 34.

36 : https://www.energynetworks.com.au/news/energy-insider/rise-machines-will-electric-vehicles-dominate-future accessed 4 September 2019

37 AEMO, 2018 Electricity Statement of Opportunities, August 2018, pp. 31–32.

38 AEMO considered the following four scenarios: (1) convenience charging scenario – vehicles assumed to have no incentive to charge at specific times, resulting in greater evening charging after vehicles return to the garage (2) daytime charging – vehicles incentivised to take advantage of high PV generation during the day, with available associated infrastructure to enable charging at this time (3) night-time charging – vehicles incentivised to take advantage of low night-time demand (4) highway fast charging – vehicles that require a fast charging service while in transit, based on a mix of simulated and actual arrivals of vehicles at public fast charging from CSIRO research.

39 Andrew Dillon, Electric vehicles, when, not if, https://www.energynetworks.com.au/news/energy-insider/electric-vehicles-when-not-if, 11 April 2019, viewed 4 September 2019.

> One thing we have to get right is ensuring much of the electric vehicle charging is shifted away from peak demand periods. Peak demand – when customers are consuming the most – tends to occur on really hot summer days in the early evening.
>
> The good news is this shouldn't be hard. We need a combination of sensible pricing structures to encourage off-peak charging and smart charging infrastructure to do so. Experience in the UK shows 75 per cent of electric vehicles are charging for less than 40 per cent of the time they're plugged in and hence the demand can easily be shifted away from peak periods.

A recent study outlines three key complementary strategies for integrating EVs:[40]

- Smart pricing – dynamic and locational signals to encourage people to shift or reduce consumption, but also to reward increased consumption and demand side flexibility when DER is active
- Smart technology – automation to enable management of consumption and automatic response to signals
- Smart infrastructure – using charging and grid infrastructure (existing and new) to enable smart pricing and technology, and respond to changing patterns of behaviour/use.

The Commission is working closely with the EV Grid Integration Working Group, which also includes the AER, AEMO, ARENA, Australian Energy Council, Commonwealth Department of the Environment and Energy, ECA, Electric Vehicle Council and ENA. The purpose of this working group is to provide a central forum for key industry and government stakeholders to collaborate and coordinate activities, and promote policy and regulatory development before wide scale EV adoption begins. The goal is to demonstrate a pathway for efficient integration of EVs into existing markets and infrastructure.

40 Hildermeier, J., Kolokathis, C., Rosenow, J., Hogan, M., Wiese, C., and Jahn, A., Start with smart: Promising practices for integrating electric vehicles into the grid. Brussels, Belgium: Regulatory Assistance Project, April 2019.

3 OPTIONS TO FACILITATE GREATER ACCESS TO THE GRID FOR DISTRIBUTED ENERGY RESOURCES

In a high DER future, the electricity system (especially at the distribution level) is increasingly likely to have multi-directional flows and become a platform to support a range of different services that future electricity system users may demand. Access arrangements will become increasingly important as customers' ability to buy or sell services rests on their ability to access the electricity grid.

As discussed in Chapter 2, reforms to distribution pricing cannot be considered as a stand-alone issue. Any reforms to implement export charging in the context of a high DER future will need to consider interactions with the nature of the access regime at the distribution level, as well as other aspects such as DNSPs' connection obligation and service performance standards.

This chapter will explore the role of the access and connections framework, and changes that could be made to maximise the benefits of DER for all consumers.

3.1 Risks emerging under the current open access framework

3.1.1 The current open access framework

Currently, distribution (and transmission) networks in the NEM operate under an open access regime for the connection of generation. This means generators, whether they are grid-scale renewable generators or small customers with roof-top solar systems, do not pay for their use of distribution or transmission networks in exporting energy, beyond a shallow connection charge to connect to the network.[41]

For distribution networks, the connection charge varies with the type of connection service.[42] The connection charge also depends on the size of the connection and its proximity to shared network assets.

While generators are not required to pay use of system charges when they export energy, they in turn do not receive firm (or guaranteed) access to the network – any individual generator can be constrained off if the network is constrained. Under the National Electricity Rules, network service providers are obliged to allow new generating units to connect to their networks.[43] This means DNSPs could not avoid connecting DER to the parts of their distribution network even if connecting them would cause technical issues, provided they meet basic requirements.[44] These technical issues are further discussed below.

41 NER, clause 6.1.4.

42 NER, Chapter 5A, Part B.

43 NER, clause 5A.B.1.

44 For example, compliance with the relevant Australian Standards and the local service and installation rules.

3.1.2 DER integration issues are emerging under the open access regime

As DER penetration increases, some DNSPs are starting to face technical issues. DNSPs that currently have high penetration of rooftop solar systems have started to experience network congestion issues in some of their areas as their LV networks are reaching hosting capacity limits.[45] These limits can take two forms:

- **Thermal limits.** Thermal limits are related to power flow. This is where wires and other equipment are not able to carry any more power because the equipment has reached its upper temperature limit. Continually operating network equipment beyond their thermal limit will lead to overheating, reducing its working life or leading to equipment failure. To mitigate this risk, DNSPs usually choose low voltage fuses and set circuit breakers so that supply is interrupted when temperature limits are exceeded.
- **Voltage limits.** This occurs when voltage, or electrical pressure, reaches its upper threshold as more and more generating units attempt to inject power to the grid.[46] Rooftop solar systems are generally designed and configured to reduce output or disconnect from the grid (i.e. trip) when the upper network voltage limit is reached to ensure the LV network operates within its technical capability.[47] On LV networks, voltage limits are usually reached before thermal limits are reached, as shown in the following SA Power Networks analysis.[48]

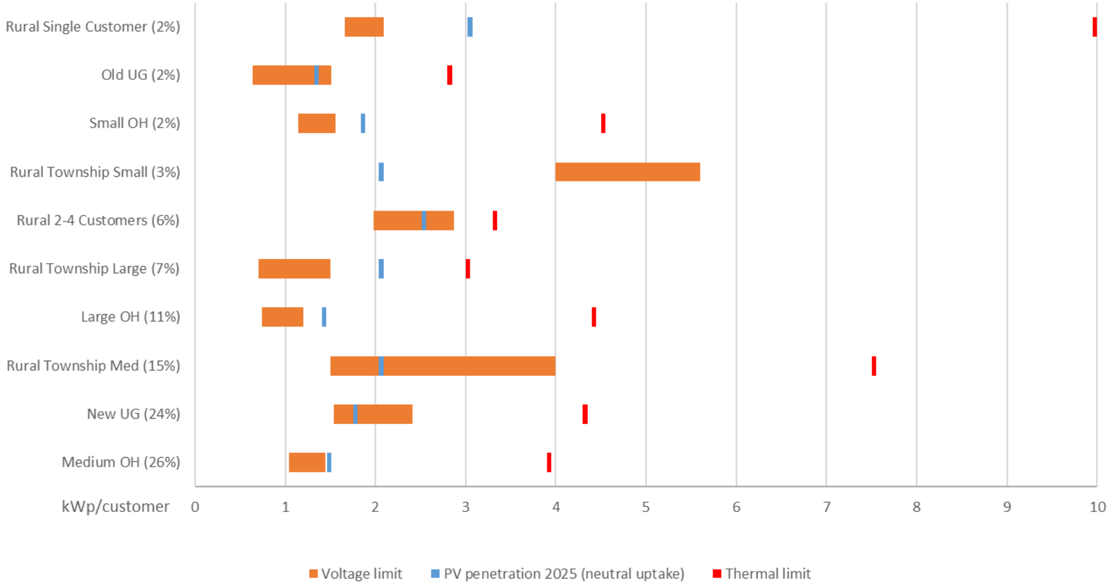
45 The term 'hosting capacity' refers to the amount of DER that can be accommodated on the distribution system at a given time and at a given location under existing grid conditions and operations, without adversely impacting safety, power quality, reliability or other operational criteria, and without requiring significant infrastructure upgrades.

46 In order to inject power into the electricity grid, a DER installation has to inject electricity at a higher electrical pressure (voltage) than the local network's electrical pressure (voltage). The local network voltage therefore rises as more and more power is injected.

47 The Commission notes that some older inverters did not necessarily curtail their output when upper voltage limits were reached, resulting in overvoltages. Recent changes to technical standards mean that electricity exports from new and correctly installed solar PV installations are unlikely to cause technical or safety issues for DNSPs. This is because exports from those installations will automatically reduce or stop as (voltage based) capacity limits are reached, meaning that some solar PV owners are not able to sell their output.

48 SA Power Networks, *Maximising customer value from the network in a high-DER future* AEMC / ARENA Regulatory DEIP dive, 6th June 2019, slide 7.

Figure 3.1: SA Power Networks, Average PV penetration and network limitations by network type today



Source: SA Power Networks

3.1.3 NSPs are affected by DER penetration in different ways

The nature and magnitude of these technical impacts differ between DNSPs (and sometimes within a DNSP's operating area) as the penetration of DER differs between locations. DNSPs that have greater network capacity and lower solar PV penetration are experiencing fewer issues while others such as SA Power Networks and Energy Queensland are experiencing greater technical impacts.

For example, some zone substations in Endeavour Energy's urban network area have close to 100 per cent solar penetration. A strong urban network means that Endeavour Energy has not experienced widespread technical issues.[49] In contrast, at the urban fringe of Endeavour Energy's network, where the system is less robust, customers have complained about loss of generation and curtailment.[50]

In jurisdictions such as South Australia and Queensland, where there is a high level of solar penetration, the Commission has observed that some DNSPs have started to restrict the level of electricity that DER can export to the grid to manage technical issues caused by DER exports. These restrictions are being imposed as basic connection size or export limits, with some customers facing very low or even zero export limits in areas of the network with high

49 For example Kellyville and Bungarribee zone substations. Information presented by Endeavour Energy at the AEMC/ARENA Regulatory DEIP Dive, 6 June 2019.

50 Endeavour Energy provided an example where customers at Sydney's south western suburb of Kentlyn experienced volt-watt curtailment and trips.

levels of solar penetration. As DER uptake increases, DNSPs have signalled that allowed export limits are likely to be reduced even further.

In response to increasing solar PV penetration, SA Power Networks reduced its standard export limits from 10kW to 5 kW in 2017. It has indicated that this limit is likely to be reduced further in the future.[51] In Queensland, Ergon Energy and Energex have also introduced partial and minimal export connection options for small scale generators.[52]

3.1.4 Static restrictions are not a sustainable way to manage DER integration

Reducing (or constraining) the export limit is a low cost way to limit an increasing level of DER export levels, potentially requiring network expenditure to manage voltage issues. However, imposing such limits as fixed and broad restrictions is unlikely to be economically efficient. Such application of fixed limits does not take into account the locational (and sometimes time-of-day) nature of export related congestion and prevents DER from connecting or exporting in areas of the network where there may not be congestion issues. Solar generation has near zero marginal cost, meaning broad-based export restrictions limit the dispatch of the lowest cost generation, increasing energy costs for customers.

As static restrictions are often applied on a 'first in, best dressed' basis, this also creates equity issues between customers who have connected at different times. Customers who connected their DER when the network was not congested would continue to enjoy a high export limit while customers who have connected at a later stage may face much lower or even zero export limits. Such an approach is increasingly seen as unacceptable to customers who have invested in DER but have very limited opportunities to monetise the benefits.

3.2 Options to facilitate greater DER access

3.2.1 'Building out' the network is not an efficient solution

Augmentation, or 'building out' the network would increase its capacity to integrate more DER. However, augmentation is costly and may be an inefficient solution to provide additional network capacity for the following reasons:

- **Congestion is often time limited.** While network augmentation could to targeted to address locational congestion, the additional network capacity is only needed some of the time. Even in jurisdictions with high solar penetration such as South Australia, AEMO's forecast shows that, even by 2035, issues caused by excess energy injection into the grid are likely to occur less than 10 percent of the time. Without reforms to the charging arrangements discussed in Chapter 2, the cost of augmentation would be recovered from energy consumed by customers, with the benefit of additional capacity enjoyed by those that have access to DER.
- **Augmentation locks in investment.** Under the current regulatory framework, the capital expenditure component of the augmentation is rolled into the regulatory asset

51 SA Power Networks, *Maximising customer value from the network in a high-DER future: Presentation to AEMC/ARENA Regulatory DEIP Dive, 6 June 2019.*

52 See Joint Standard Document between Energex and Ergon Energy - *Connection standard: micro embedded generating units (0 - ≤30 kVA)*, EX STD01143 Ver 4.0; EE STNW1170 Ver 4.0; section 5.4.

base (RAB) and customers pay for such investment over the life of the asset, which could be between 20-50 years.[53] As technological development increases in pace, it is possible that new technologies might offer solutions that could increase capacity at a lower cost, before DNSPs have fully recovered the costs of their investment. Such an approach could lead to customers paying unnecessarily high network prices.

3.2.2 Dynamic or flexible export limit is a potential interim solution

Dynamic or flexible export limit explained

A potentially more efficient solution to integrating a higher level of DER is the application of dynamic or flexible export limits. Instead of applying a low static export limit to all consumers or augmenting the network, this solution recognises that technical issues caused by DER exporting to the grid generally do not occur frequently, and a DNSP may only need to constrain DER output on occasions so that its networks can operate within capacity. This could involve DNSPs taking on a more active role in managing flows in their networks by remotely communicating with the active DER, such as batteries, to allocate spare export capacity on a locational and time-varying basis. DNSPs would then dynamically restrict consumer exports during times and in locations where there is a capacity constraint, instead of passively restricting exports through inverter responses to voltage.[54] Dynamic export limits would be adjusted by the DNSP based on distribution network conditions at different times.

Dynamic export limits are being considered by DNSPs such as SA Power Networks that are already facing a high level of DER penetration. SA Power Networks has proposed to implement flexible export limits in the 2020-25 regulatory period. Under this proposal, SA Power Networks' customers will be able to choose between a static limit that applies at all times (currently 5 kW but likely to reduce to 3 kW) or a dynamic limit of 10kW that can be reduced at times when the network is congested.[55]

The Australian Renewable Energy Agency (ARENA) is also funding a study exploring dynamic export limits on DER as a way to help manage the distribution network more efficiently and therefore increase the overall ability of consumers to utilise the distribution network.[56]

Importantly, SA Power Networks' proposal to implement dynamic export limits is supported by a cost-benefit analysis. Figure 3.2 below provides a graphical illustration of the results.

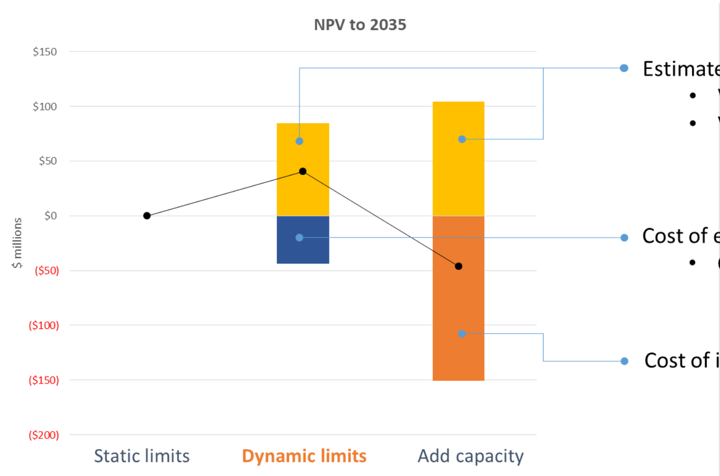
53 DNSPs recover the costs of capital investment through regulatory depreciation plus allowed rates of return on the residual capital value.

54 https://talkingelectricity.com.au/wp/wp-content/uploads/2019/05/Solar-options-paper_May-2019.pdf, p. 16.

55 In fact, such option is already offered to SA Power Networks's customers whose generator is greater than 200kW. See https://www.aer.gov.au/system/files/SAPN%20response%20to%20CCP14%20advice%20to%20AER.pdf, p. 2

56 Ibid.

Figure 3.2: SA Power Networks modelling of strategies that increase DER hosting capacity



Source: SA Power Networks
Note: The above analysis was presented by SA Power Networks at the AEMC/ARENA DEIP Dive on 6 June 2019.

The need for a common value of customer export methodology

SA Power Networks' analysis showed that the implementation of dynamic export limits provides greater net benefits compared to static limits or adding network capacity through augmentation. Crucial to its analysis is the estimated economic value of exported energy. The Commission understands that SA Power Networks, with assistance from expert consultants, developed a methodology that is based on the regulatory investment test for distribution (RIT-D). As DER penetration increases, there will be an increasing need for a consistent methodology that is applied for all DNSPs conducting similar analysis.

As part of the DEIP DER valuation package of work discussed in Chapter 1, the Commission will work together with ARENA, the AER, consumer groups as well as other stakeholders to help to develop a standard methodology for DNSPs to estimate value of customer export, which could be used to determine the value of a marginal increase in export hosting capacity.

Some expenditure may be required to enable implementation of dynamic export limits, but the magnitude is likely to differ between DNSPs

Implementing dynamic export limits (as well as other solutions to improve a distribution network's ability to integrate more DER) is likely to require a level of additional DNSP expenditure. Some of the expenditure could include building an LV hosting capacity model, sourcing data as part of implementing LV monitoring and the calculation of flexible export limits. The level of additional expenditure required is likely to differ between DNSPs as they each have varying levels of DER penetration currently and different forecast uptake.

The Commission also notes enabling dynamic export limits does not necessarily rely solely on capital expenditure and that technology solutions currently already allow DNSPs to procure some of their requirements from third party providers. For example, a DNSP may only need to install a small number of network monitoring devices to improve LV networks visibility, and supplement the information by purchasing data from metering data providers.

As discussed in the *2018 Economic regulatory framework review*, the Commission considers the incentive-based regulatory framework provides DNSPs the ability to undertake, and the AER the ability to approve such expenditure, if it is prudent and efficient.[57] Indeed, DNSPs such as SA Power Networks and Energy Queensland have included DER integration related expenditure in the regulatory proposals for their upcoming regulatory periods, which are currently under consideration by the AER.

As the AER is also expecting to receive requests for DER integration expenditure in future regulatory proposals, it has commenced developing a set of guidelines on how it intends to consider proposals for DER integration expenditure as well as what it considers as prudent approaches in integrating DER. The Commission supports the AER in developing this guideline as it provides a level of certainty to DNSPs on how their proposed expenditure will be assessed.

3.2.3 Considering networks charging and access reforms holistically

Chapter 2 of this report discussed the need to consider reforms to the current consumption-only charging framework as the electricity system evolves. The need for such reforms also reflect the concerns from consumer groups that the current framework is leading to inefficient and inequitable outcomes. As discussed in Chapter 2, reforms to the charging framework cannot be considered alone as changes are likely to affect other parts of the regulatory framework. The distribution access framework is one such area.

Customers' interactions with the electricity system (and in particular, the distribution network) will be become more diverse in the future. While most customers will continue to use networks to import electricity from the grid, the networks will also be used by other consumers to access new energy services markets. The regulatory framework needs to accommodate this diversity of use and enable DNSP to develop and price new services that meet the evolving needs of all consumers. Through the DEIP DER Access and Pricing Working Group, the Commission will work with all stakeholders in considering potential new access arrangements that may form part of DNSPs' new service offerings. Some of the potential options could include:

- **Options to select varying levels of static export limits.** DNSPs' future connection agreements could provide customers the option to select a level of static export limits to suit their preferences. For example, a customer who prefers to maximise exports might choose to pay a higher connection charge in return for a higher level of export limits. This could be thought of as similar to current mobile phone or broadband plans where the customer chooses their data limit or upload/download speeds.
- **Options to choose different level of access.** The above option could be offered in conjunction with options that allow consumers to choose different levels of firmness for how much their exports would be limited below their standard limits at time when the

57 AEMC, *2018 Economic regulatory framework review: promoting efficient investment in the grid of the future,* July 2018.

DNSPs need to impose network constraints. This could be a simple choice between a static or dynamic limit as proposed by SAPN, or it could be a type of optional firm access product where customers that purchase the product are less likely to face constraints than other customers, or receive compensation if they are constrained to below a certain agreed level.

- **Operating envelopes.** It is important to note that potential new service offerings above do not have to be limited to the 'export' aspect of the connection agreement. DNSPs are increasingly considering the concept of 'operating envelopes'. Operating envelopes are a dynamic value range (positive or negative) provided at the NMI level that defines the DER generation or load limits. Operating envelopes enable all DER bids entering the wholesale or FCAS markets to be dispatched without further consideration of distribution constraints.[58] This concept is discussed further in AEMO and ENA's Open Energy Networks *Interim Report: Required Capabilities and Recommended Actions*.

3.2.4 Working with stakeholders to deliver reform

Any reforms to distribution access, connections, and charging arrangements would be complex. Such reforms would also be 'world's first' as other international jurisdictions are yet to face the issues faced by DNSPs in Australia.

The 2019 Review is the start of the reform journey. The Commission has been consulting broadly with the industry to understand the need to reforms and has been working closely with consumer groups to consider reform options. Through DEIP, the Commission will work with stakeholders, who we understand intend to submit rule change requests, to further progress reforms to DNSPs' access, connections and charging arrangements.

If rule change requests on access and connection arrangements are not received by early 2020, then as part of the *2020 Economic regulatory framework review* (2020 Review), the Commission will consult on and develop detailed proposals for changes to distribution system access and connection arrangements to support consumers' needs while minimising total system costs.

3.3 Actions that DNSPs can take now to improve DER hosting capacity

As stakeholders work together to progress access and charging reforms, there are some cost effective strategies that DNSPs could potentially implement now to increase networks' hosting capacity to enable more DER to be connected or reduce the instances of export constraints in the short term. These include:

- Changing voltage transformation ratios at local distribution substations, provided minimum voltages can be maintained. Distribution substations in a low rise residential area usually feed a few blocks.
- Changing settings on the automatic voltage control equipment at zone substations, provided minimum voltages can still be maintained at all times and at all locations on the network. Zone substations feed large areas, usually including multiple suburbs

58 AEMO and ENA, Open Energy Networks consultation response, December 2018, p.11.

- Applying different inverter settings (volt/var response) to the DER. Improved settings have been proposed for new installations.[59]

A detailed discussion of these strategies can be found in Appendix F.

3.4 Open Energy Networks

Another significant project that has considered the issue of distribution access is Open Energy Networks. Open energy networks is a joint Energy Networks Australia and AEMO project examining operating and market requirements for the integration of distributed energy resources.[60] The project is considering three core market and distribution system operator options, plus a hybrid option. All options involve the receipt of bids for distributed energy and ancillary services via aggregators or retailers. In each case distribution (and transmission) network constraints are imposed on the bids in order to determine whether (and which) bids are constrained off. Bids are then optimised, inclusive of constraints, and dispatch instructions for energy and ancillary services are provided to aggregators or retailers.

The three core options are based around three different market platforms. These are:

- a distribution system operator (DSO) market platform
- an AEMO market platform or
- an independent distribution system operator (IDSO) market platform.

The preferred hybrid model has an AEMO market platform, as well as a separate but integrated distribution services market platform which is administered by AEMO but which has network data populated by the DNSPs.

The need for network visibility, and in particular the data, modelling and level of accuracy requirements for determining real time constraints, is a common key issue.

A cost benefit analysis is currently being undertaken on each of the options. The analysis may help to inform a decision on the preferred market platform, as well as the optimum timing, sequence and extent of any market platform rollout.

3.5 Is there a need to consider obligations on DNSPs to manage export constraints?

While many options for increasing export capacity are not costly, there is currently little incentive for DNSPs to invest in measures to reduce export constraints. Networks will automatically stay within technical limits as inverters simply cease to export when limits are

59 AEMO, *Technical Integration of Distributed Energy Resources - Improving DER capabilities to benefit consumers and the power system*, April 2019, pp. 50-51.

60 For full details see the following joint AEMO and Energy Networks Australia Open Energy Networks publications: *Interim report - required capabilities and recommended actions*, July 2019; *Consultation response*, December 2018; *Consultation on how best to transition to a two-way grid that allows better integration of Distributed Energy Resources for the benefit of all consumers,* June 2018.

reached.[61] Most negative impacts from export constraints are seen by owners of DER and by consumers, not by the DNSPs.

The network regulatory framework currently imposes no consequence on DNSPs for constraining off DER generation, and similarly provides no benefits for increasing DER hosting capacity where this is in the long term interests of consumers. To the contrary, even if network revenue allowances have been built up on the basis of constraints being addressed then, in the absence of a countervailing output incentive, the operation of incentive schemes such as the efficiency benefit sharing scheme (EBSS) and capital efficiency sharing scheme (CESS) incentivises under-expenditure, with no penalty for under-delivery of export capacity. The work that some DNSPs have done in addressing export constraints has therefore not been driven by regulatory reward. While the regulatory investment test (RIT-D) provides a means to recover efficient expenditure,[62] it does not necessarily encourage it.

There may therefore be merit in considering explicit DNSP incentives for managing export constraints, either through pricing arrangements or as an enhancement to the existing service target performance incentive scheme (STPIS). Measuring constraints may prove challenging as DNSPs have limited visibility of their LV networks (this is further discussed in Chapter 4), meaning that any incentive scheme would require careful design and may need to be implemented over some years. The Commission will consider the need for such incentives as part of the consideration of access and charging arrangement reforms.

61 as long as settings have been specified and applied correctly, and the inverter is operating as designed.

62 NER, rules S6.2.2(3) and 5.17.

4 INFORMATION TO SUPPORT DECISION MAKING IN A SMART GRID

Information is required in order for customers and network operators to make informed decisions on what investments to make and how to manage around network constraints. Exports constraints are largely driven by low voltage circuit limitations, however, very little low voltage circuit information is published.

Some relevant and useful information could be made available from existing equipment such as smart meters and inverters at relatively low cost. Other information may be highly beneficial to decision-making but may also require costly new equipment to be installed.

This chapter:

- examines the benefits of increased information availability
- provides a stocktake of what information is currently available and
- discusses potential and emerging information sources, and how these might be leveraged in future.

4.1 How information provision will help consumers maximise the value of DER

The DER transition is being driven by consumers, who are choosing to adopt DER technologies such as solar PV, batteries and electric vehicles at increasing rates.

Information helps consumers make informed choices about what DER to invest in. For example, information on the level of network congestion could assist consumers in deciding whether to invest in solar panels, or whether to invest in batteries, demand response or other forms of DER.

Real time information would also allow customers who already have active DER, such as batteries or controllable load to optimise its use. For example, customers with batteries could import energy for charging purposes at low price periods or when local exports are constrained, or could provide existing and evolving frequency control ancillary services (FCAS) and distribution network support services when network capacity is available. Customer decisions would be based on information about real time prices in the various markets, and on information about congestion in the distribution network.

Simplicity is also important. Consumers may not want to invest substantial and valuable personal time interacting with the electricity supply system. For controllable DER, real time DER optimisation services are likely to be provided by a third party agent, such as an aggregator or retailer, or to be automated. Information needs to be made available to all parties and to any software in a readily usable form so that optimisation can take place.

4.2 How information provision would help DNSPs to better serve their customers

Information assists service providers, such as DNSPs to make investments that support the choices that consumers make in a way that maximises total benefits for all consumers. Constraints on access to energy and ancillary services markets could have a material impact on the return that a consumer can obtain from their DER investment.

The Australian Energy Regulator (AER) could also rely on information to determine whether network augmentations proposed by the DSNPs would provide optimised consumer benefits.

As discussed in Chapter 3, there is a trade-off between:

- reducing constraints, which would provide greater access for DER generation and reduce wholesale energy and ancillary services costs, and
- the additional network charges that would be needed to cover the costs of building out or reducing constraints.

This optimisation is difficult in the absence of information on what constraints are binding, when they bind and how material they are.

AEMO and Energy Networks Australia (ENA) consider that better information is necessary for DER integration:[63]

> Successful management of DER is an integral feature of any feasible future energy system. These required capabilities are:
>
> - Enabling DNSPs to improve network visibility – i.e. know where DER are installed and how they are capable of behaving in real-time so the local distribution network and the wider system can be managed. For example, the export capacity of a solar and storage system needs to be known, as well as how fast the battery can respond to a signal to switch from charging to discharging.
> - Defining network constraints or 'operating envelopes' so customers can be advised how much electricity they can export and/or import from the grid. These operating envelopes define the limits that customers' DER must operate within for the safe and secure running of the network and the overall electricity system. For limits to be established, real-time data must be collected and communicated, based on standard protocols.
> - Establishing standards to communicate these 'operating envelopes' to aggregators, retailers, owners of DER and AEMO to help ensure the safe and secure operation of the network.

63 AEMO and Energy Networks Australia, Open energy networks, interim report - required capabilities and recommended actions, 2019, p.4.

4.3 Currently available information

At present consumers have almost no visibility of the network beyond their own installation. Some consumers do monitor their own DER through third party internet based services, with data collected either by their own inverters or by third party monitoring equipment.[64]

DNSPs have good data visibility at higher levels of their distribution networks, through their supervisory control and data acquisition (SCADA) systems. However, they generally have little visibility over their low voltage networks, which is where most DER constraints occur.[65] To assist this review the Commission, in consultation with ENA, undertook a survey of the load and voltage data that DNSPs collect at lower levels of their networks. Survey responses were received from all DNSPs in all mainland states, plus the ACT. The responses revealed that:

- DNSPs have excellent data on loads and voltages at their zone substation circuit breakers, where primary distribution feeders (typically 11kV or 22kV) originate
- in general DNSPs have very limited information on real time loads and voltages downstream of the zone substations. Some of the monitoring that does occur is ad hoc or, alternatively, measures only scant data, such as the maximum demand that occurs between site visits.
- with the exception of Victoria, where meters are still owned and controlled by DNSPs, distributors collect little information at customer premises level beyond energy related settlement and billing data.
- there is very little monitoring of DER generation output by DNSPs. Net metering arrangements mean that only the total site is monitored.

The survey results are summarised in Appendix C of this report. The Commission greatly appreciates the DNSPs making this information available.

This limited visibility on the low voltage distribution networks makes it difficult for DNSPs to optimise the level of congestion, for customers to make informed investment decisions or for customers or their agents to make informed operational decisions.

Limited visibility makes it difficult for a DNSP to determine where constraints exist or where they are likely to develop in the future. This in turn makes it difficult for a DNSP to find optimal solutions for alleviating these constraints.

As discussed in chapter 3 and appendix F, constraints generally occur when voltage limits are reached on low voltage circuits. These constraints can reduce the ability of DER to export onto the distribution network for a period of time,[66] reducing the value of DER investments that consumers and governments (where subsidies exist) have made. As with constraints on the transmission network, if the benefit (to consumers) of addressing the constraint exceeds the cost (to consumers) of doing so, then the constraint should be addressed.

64 For example, Wattwatchers or solar analytics' equipment.

65 SA Power Networks, *Maximising customer value from the network in a high-DER future*, Presentation for AEMC/ARENA Regulatory DEIP dive, 6 June 2019, slide 5.

66 Monishka Narayan, 28 February 2019, 'Could the solar boom bust the grid?', Energy Networks Australia Energy Insider, viewed 26 August 2019, https://www.energynetworks.com.au/news/energy-insider/could-solar-boom-bust-grid.

As discussed in chapter 5, better information may also assist DNSPs and the Australian Energy Market Operator (AEMO) to mitigate overall risks to system security that could cause unplanned outages. DNSPs may also be able to use the information to help them determine the best times to conduct routine maintenance of the distribution network while minimising the impacts of doing so on customers.

While there are benefits of gathering and disseminating additional information, there are also costs, such as those associated with installing new monitoring equipment. Both the costs and the benefits of information gathering need to be considered. Complementary options such as modelling could be used to reduce the amount of information needed to support DER related decision-making. The most cost effective means should be used in order to obtain necessary information.

4.4 Potential and emerging information sources

There are endless options for data collection and constraint determination. Some options are likely to be more cost effective than others. Options that leverage off existing equipment and data sources are likely to have a much lower cost than options that involve the installation of new equipment, or options that involve procurement of data from proprietary sources. Similarly, combinations of data sampling and network modelling may be more cost effective than network wide monitoring.

Potential opportunities to make better use of existing information sources are discussed below.

4.4.1 DER register

In September 2018, the Commission made a rule requiring AEMO to establish a register of distributed energy resources. This provides static data on the DER systems connected to the NEM. The data on each installation includes the installed capacity, and the make and model of inverter used for the DER system.[67] AEMO has developed information guidelines for the register and is preparing to implement it in December 2019.[68] AEMO will need to collect information for this DER register from DNSPs and TNSPs.[69] AEMO may also collect other relevant information, such as Clean Energy Regulator data.[70] AEMO will need to share certain DER register information with network service providers and publicly report appropriately aggregated data.[71] Aggregated DER register information will be published on AEMO's website.[72] This information will assist AEMO in determining how the system is likely to behave

67 Australian Energy Market Commission, National Electricity Amendment (Register of distributed energy resources) Rule 2018 No. 9. Under this rule, rule 3.7E(b)(1) of the National Electricity Rules (NER) refers to the DER register needing to include DER generation information reported to AEMO by network service providers. DER generation information is standing data in relation to a small generating unit. These provisions will take effect in December 2019. See also AEMO, *Technical Integration of Distributed Energy Resources*, April 2019, p. 20.

68 AEMO, 'NEM Distributed Energy Resources (DER) Register Information Guidelines Consultation', viewed 26 August 2019, https://www.aemo.com.au/Stakeholder-Consultation/Consultations/NEM-Distributed-Energy-Resources-Information-Guidelines-Consultation.

69 Register of distributed energy resources Rule 2018 No. 9, introducing NER rule 3.7E(b)(1).

70 AEMO, *DER register information guidelines*, May 2019, p. 6. Under the Register of distributed energy resources Rule 2018 No. 9, NER rule 3.7E(b)(3) suggests that AEMO can supplement the DER register with data that is available from other sources.

71 Register of distributed energy resources Rule 2018 No. 9, introducing NER rules 3.7E(l) and 3.7E(n).

normally and during system disturbances and could help consumers and market participants to determine the quantity of DER installed and operating in their area, which could in turn help to inform their modelling and long-term DER related investment decisions.

4.4.2 Smart meter data

Smart electricity meters are another source of data for consumers and market participants. One of the major benefits of making use of smart meter data is that the framework and infrastructure for smart meters already exists and new smart meters are being installed all the time. There is no requirement to install additional equipment or to replace existing equipment.

A competitive smart meter rollout is currently occurring across large portions of the NEM following the Commission's *Competition in metering* reforms,[73] while a separate Victorian smart meter rollout led by the Victorian government has led to nearly all Victorian customers having advanced meters.[74] Future customers with DER are likely to have smart meters installed, and some smart meter data is already being collected.

Smart meters allow consumers and market participants to see both incoming and outgoing flows of electricity.

Smart meters are already capable of providing a large amount of information about voltage, consumption and exports.[75] In addition, as discussed below, many off-the-shelf smart meters can provide a lot more information than the National Electricity Rules (NER) currently require them to. However, the only data currently shared by or available through market systems is settlement data, which in most cases relates solely to energy imports and exports.[76]

The current framework for information collected from meters

Under the current framework in the NER, customer meters provide metering data,[77] which is data on the consumption and export of electrical energy.[78] In addition, a new meter must be capable of providing information on request regarding non-metering data components, such as voltages, current, power, supply frequency and events under a set of minimum specifications in the NER.[79]

Three parties have responsibilities for metering data. The Metering Data Provider (MDP) establishes and maintains a metering data services database,[80] and the Metering Coordinator (MC) is responsible for retaining metering data in the metering data services database.[81] This

72 Register of distributed energy resources Rule 2018 No. 9, introducing NER rule 3.7E(l).

73 Additional information on the state of the competitive smart meter rollout across much of the NEM is available in Appendix B of this report.

74 State Government of Victoria, 9 June 2017, 'About meters', viewed 26 August 2019, https://www.energy.vic.gov.au/renewable-energy/victorian-feed-in-tariff/premium-feed-in-tariff/about-meters.

75 Table S7.5.1.1 of the NER, item 1(e).

76 See the definition of 'settlements ready data' in Chapter 10 of the NER.

77 Including accumulation and interval (smart) meters.

78 See the definitions of 'metering' and 'metering data' in Chapter 10 of the NER.

79 Table S7.5.1.1 of the NER, item 1(e).

80 Clause 7.10.1(a)(5) of the NER.

81 Clause 7.3.1(a)(2) of the NER.

database contains metering data and relevant NMI standing data.[82] AEMO maintains a separate metering database which includes some metering data,[83] settlements ready data[84] and information for each metering installation registered with AEMO.[85] AEMO obtains this data from MDPs and MCs.[86]

The NER specify that AEMO and the consumer's DNSP are two of a small number of parties that are allowed to access or receive metering data, settlements ready data, NMI standing data and data from the metering register for a metering installation without customer consent.[87] These parties can request metering data and relevant NMI standing data from MDPs,[88] as well as the metering data, settlements data and information for each metering installation from AEMO.[89] As noted above, this data relates to energy consumed and exported.

A DNSP can also request data on voltages, current, power, supply frequency and events associated with the meters of its customers, while a small customer can provide permission for a market participant to access this data for their meter.[90] However, the metering coordinator is at liberty to charge a negotiated fee for providing these services.[91]

In addition, the NER and National Energy Retail Rules (NERR) allow small or large customers or a customer's authorised representative to request metering data from their retailer or DNSP relating to their own metering installation.[92] However, this metering data is data related to energy. It does not include voltage information or other types of information.[93]

Smart meters are capable of providing additional data beyond that mandated in the NER. For example, some smart meters can capture power quality event data, including total harmonic distortion and sag/swell data, down to 5 cycle resolution, based on programmable trigger levels.[94]

The NER contain various provisions designed to keep metering data secure.[95] There are also provisions in the NER to protect the privacy of consumer data by restricting the parties to

82 This is technical data about a consumer's electricity connection point that describes the characteristics of the connection point. It includes details of the relevant distribution network tariff. For more details, see the definition of 'NMI standing data' in Chapter 10 of the NER.

83 This is consumption data collected from the meter.

84 This is metering data that has undergone a validation and substitution process by AEMO for the purpose of settlements and is held in the metering database.

85 Clauses 7.11.1(a) and (c) of the NER.

86 Clauses 7.10.3 and 7.3.1(a)(2) of the NER.

87 Clauses 7.15.5(c)(1) and (c)(5) of the NER.

88 Clause 7.10.3(a) of the NER.

89 Clause 7.11.1(d)(1) of the NER.

90 Table S7.5.1.1 of the NER, item 1(e)

91 Clause 7.6.1 of the NER.

92 Clauses 7.15.5(d)(2) and (3) of the NER; clause 15.2A of the model terms and conditions for deemed standard connection contracts in schedule 2 of the NERR.

93 See definitions of 'metering data' and 'metering' in Chapter 10 of the NER.

94 EDMI, *Mk7C Factsheet - MKT-FS-032 Rev 02*, 2019, p. 2.

95 See clauses 7.15.3 and 7.15.4 of the NER.

which MCs,[96] MDPs[97] and AEMO[98] can provide consumer data. These provisions also govern the circumstances under which the data can be provided to authorised parties.

In order to make informed investment and operational decisions customers, customer agents and network service providers need to have access to constraint and capacity information for the entire circuit to which customers are connected, not just the status of their own, or one individual customer's connection. Appropriate individual privacy rights should be maintained, particularly around personal information. However, in regard to power flow and voltage levels, an appropriate balance should be struck between privacy obligations and the benefits of broad reporting.

The benefits and limitations of accessing data from meters

In summary, modern smart meters collect, and are capable of collecting a large suite of useful information. Only a fraction of this information, energy data used for settlements, is automatically stored and freely available to DNSPs, AEMO and retailers.

Broader collection, storage and access to this information may be in the long term interests of consumers. The marginal cost of collecting, storing and making a much wider suite of data available may be small, particularly for new installations where meters can be pre-configured with broader data requirements, or where existing meters can be remotely re-programmed.

The value of additional metering information may be substantial. As constraints on LV networks are largely voltage driven,[99] meter voltage and export information will provide direct evidence of when and where voltage limits are being reached. This would allow DNSPs, prospective DER investors and customers to make appropriate investment decisions, and allow the AER to better assess those decisions. Disturbance information may also provide insights into the behaviour of and waveforms on LV networks during system disturbances, analogous to the information currently available through fault recorders on transmission networks.

DNSPs can already obtain consumption and export settlement data for free from AEMO. However, export congestion is being driven predominantly by voltage rather than power flows. DNSPs and other parties can only access non-metering data components collected by the meters, such as voltage data, if they negotiate a commercial arrangement with the metering data coordinator.[100]

Allowing more widespread access to broader data sets over entire populations could have significant benefits, particularly when combined with DNSP connectivity information. The availability of constraint data may inform investment and operational decisions both for DNSPs and for prospective DER investors. It may also allow modelling and estimation of the

96 See clauses 7.15.4(a) and (b) of the NER.

97 Clause 7.10.3(a) of the NER.

98 Clause 7.11.1(d) of the NER.

99 SA Power Networks, *Maximising customer value from the network in a high-DER future,* AEMC / ARENA Regulatory DEIP dive, 6th June 2019, slides 5-9.

100 Clause 7.6.1 of the NER. This does not apply to DNSPs in Victoria, which own the smart meters installed for Victorian consumers.

quantity of ancillary services available from DER. DER cannot provide ancillary services if it is constrained.

Conversely, increased mandatory data disclosure may cause base metering charges to increase. Metering co-ordinators may have relied on the potential for additional income for providing non-settlement data when offering metering services to retailers.[101] If free provision of all data is mandatory, then all costs of providing data would need to be recovered through charges for mandatory services. There would also be at least some costs associated with hosting the wider set of information and with providing access to it. Ultimately the challenge is finding the right balance, and allowing that balance to shift as data costs fall, congestion increases and technology evolves. The competition in metering rule change determination envisaged negotiated access to this data under commercial terms.[102]

Increased access to information from electricity meters would also require consideration of privacy issues, particularly if disaggregated information about the DER import and export patterns of individual consumers was widely available. A balance would need to be struck between open access to data and the protection of privacy.

AEMO has suggested that the current data access provisions would benefit from increased explanation of how consumers and their authorised agents gain access to data, the development of a ubiquitous set of standards for provision of the data and incentives to facilitate competition in the provision of data and information services.[103]

Improving value from existing meters

Existing smart meters provide potential opportunities to obtain data in a cost effective manner.

In light of the issues noted, DNSPs, in collaboration with industry and consumer representatives, may wish to explore whether, for meters:

- additional mandatory data should be collected
- additional mandatory data should be published.

If additional mandatory data should be collected or published, then the Commission, AEMO and the AER should also explore:

- how and where the additional data should be stored and published
- how privacy issues should be dealt with.

Smart meters need to exist in order to extract value from them. The Commission has been monitoring smart meter installation timeframes since the publication of the metering installation timeframes rule in November 2018.[104] The Commission intends extending this monitoring to include all issues affecting the efficient rollout of smart meters in the NEM.

101 Clause 7.6.1 of the NER.

102 Rule determination, National Electricity Amendment (Expanding competition in metering and related services) Rule 2015, 26 November 2015, particularly appendix E.

103 AEMO, *AEMO Submission: ACCC Consumer Data Register Energy Consultation Paper*, March 2019, p. 4

104 National Electricity Amendment (Metering installation timeframes) Rule 2018 No. 15 and National Energy Retail Amendment (Metering installation timeframes) Rule 2018 No. 7.

When the competition in metering rule determination was made the Commission committed to undertake a review of the state of competition in the metering services market three years after the rule commenced. The rule commenced on 1 December 2017.[105] The potential benefits of greater data collection and dissemination are likely to be significant issues for this review.

4.4.3 Consumer data right for energy

The Australian Competition and Consumer Commission (ACCC) is considering issues around the provision of metering data as part of its consultation to implement a Consumer Data Right (CDR).[106] The Australian government has announced that the energy sector is one of the first sectors in which the CDR will be implemented,[107] and the COAG Energy Council expects the CDR to commence for the energy sector in the first half of 2020.[108] In response, the ACCC has released a consultation paper considering data access models for energy data, including the information that can be obtained from meters.[109] Because the NER and NERR already enable consumers to access metering and consumption data, the ACCC's main focus for the CDR in the energy industry is on a data access model for consumer-accredited data recipients, either with AEMO as the sole data holder of a centralised data set, providing a gateway function between data holders and data recipients, or with existing data holders being responsible for providing data to accredited data recipients by themselves.[110]

The ACCC also considered potential metering or non-metering related data sets that consumers could access as part of an initial energy CDR, including relevant NMI standing data fields and DER register information, that could help consumers to understand and manage their DER usage, or help them determine how much the DER of other consumers could affect their own usage.[111]

Facilitating the CDR for energy would likely require changes to the existing arrangements for accessing metering data under chapter 7 of the NER, as well as possible changes to sections of the NERR which provide small customers and their authorised representatives with access to consumption and billing data.[112]

4.4.4 Inverter data

Other devices associated with customer DER installations such as smart inverters can also collect useful information. Inverters are installed as part of most DER installations in order to convert DC electricity produced by solar panels or batteries into AC electricity that can be

105 Rule determination, National Electricity Amendment (Expanding competition in metering and related services) Rule 2015, 26 November 2015, p.499.

106 ACCC, *Consumer Data Right draft rules out*, March 2019.

107 Australian Government The Treasury, December 2018, 'Consumer Data Right', viewed 26 August 2019, https://treasury.gov.au/consumer-data-right/.

108 COAG Energy Council, *COAG Energy Council - Meeting Communique,* December 2018, p. 2.

109 ACCC, *Consumer Data Right in Energy - Consultation paper: data access models for energy data*, February 2019.

110 Ibid, p. 7.

111 Ibid, p. 19, 21.

112 Ibid, p. 23.

used on the premises, or exported to the distribution network. Smart inverters with communications are becoming increasingly common.

Smart inverters can provide information that is not obtainable from smart meters.[113] For example, smart inverters can provide information on power produced, even where that power is consumed on the premises. In contrast, smart meters generally only measure net exports or imports.[114] Inverters could also provide information on when actual constraints occur through status reporting, providing an alternative to relying on assumptions based on network voltage.[115] For batteries, their charge states and by extension their availability for participation in markets, can also be reported. This could supplement smart meter data and help consumers, DNSPs and other market participants to make decisions on how to best deploy DER-produced energy across the distribution network.[116]

Inverters associated with active DER such as batteries are likely to have communications in order to best take advantage of multiple markets. However, inverters are part of the customer's installation. Their data and communication arrangements are largely beyond the reach of the National Electricity Law (NEL) and the NER as they are currently drafted. This may be entirely appropriate. Consumers themselves, or aggregators and retailers acting on their behalf, will be the ones most interested in the state of their installations. Where DER owners or their agents are contracting or bidding to provide ancillary services, then it will be in their own interests to have the capability to deliver what they have contracted or bid for.

Conversely, the information inverters can provide on voltage, on when they are constrained off and on the extent and nature of constraints may be useful to both DNSPs and others in determining when to make investments, what investments to make and how to operate their assets.

DER owners, aggregators and retailers may also want to overlay information on the network's capacity to host the services, and on any constraints that may apply to them, in order to manage their bidding and risk.[117] Distribution network connectivity, impedance and rating information is generally not available to non-DNSPs.

Finally, where active DER is providing services to others, such as to a market or a DNSP, then the active DER will need to be dispatchable. In some instances, such as energy balancing services, dispatch may need to be fast, requiring very little latency and high reliability in the communication method.

113 Cormac Gilligan, 9 April 2019, 'Inverter suppliers go digital', PV Magazine Australia, viewed 26 August 2019, https://www.pv-magazine-australia.com/2019/04/09/inverter-suppliers-go-digital/.

114 State Government of Victoria, 9 June 2017, 'About meters', viewed 26 August 2019, https://www.energy.vic.gov.au/renewable-energy/victorian-feed-in-tariff/premium-feed-in-tariff/about-meters.

115 Wyndham et al., 'Network Services from Distributed Solar PV and Inverters', *Peer reviewed for Asia-Pacific Solar Research Conference*, 2016, pp. 2-4.

116 Marija Maisch, 2 April 2019, 'Victoria to make smart inverters mandatory for Solar Homes', PV Magazine Australia, viewed 26 August 2019, https://www.pv-magazine-australia.com/2019/04/02/victoria-to-make-smart-inverters-mandatory-for-solar-homes/.

117 AEMO and Energy Networks Australia, *Open Energy Networks - Interim report – required capabilities and recommended actions*, July 2019, p. 4. The report notes that it is necessary to define network constraints or 'operating envelopes' so that customers know how much electricity they can export and/or import from the grid.

AEMO has proposed expanding device capabilities to allow for, among other things, coordination of DER as part of the second stage in its *Technical integration of distributed energy resources - report and consultation paper*, published in April this year.[118]

DNSPs are of course free to enter into commercial arrangements with behind the meter service providers, subject to privacy obligations.

4.4.5 Data on DNSP monitoring and investments dealing with DER

In order to make informed investment decisions, consumers and DNSPs need to ideally understand the level of existing constraints and constraint trends. In addition, consumers need to understand what their local DNSP is doing to manage current DER usage on their distribution networks, including their investment plans. This information can only be obtained from the DNSPs.

DNSPs already make some of this information available either through regulatory planning reports, including distribution annual planning reports (DAPR) in which DNSPs are required to publish their forecasts of maximum demands for relevant network assets, the constraints they have identified based on these forecasts, and their investment options.[119]

Also, for larger projects, DNSPs are required to publish information as part of the RIT-D, including costs and benefits.[120]

DNSPs also publish other reports focussing specifically on DER uptake and the options DNSPs are considering in order to facilitate DER uptake while maintaining reliable electricity flows through the distribution network.[121] These reports can feed into their revenue determination proposals. However, these reports generally discuss the DNSPs' approaches to DER management, congestion and utilisation at a high level, meaning there isn't enough detail for consumers to determine the decisions made by the DNSP that would directly affect an individual customer's DER investment decisions.

The distribution and transmission networks have begun providing additional useful information on DER for consumers by developing free online maps of Australia's electricity network, in collaboration with ARENA and the University of Technology Sydney's Institute for Sustainable Futures.[122] These network opportunity maps may provide some useful information for consumers to help inform their long-term investment decisions, such as the available distribution capacity in their areas, as well as showing where DNSPs are planning to invest in their distribution networks or how much network investment can be deferred as a result of DER uptake.[123] The maps also show available network capacity during the peak

118 AEMO, *Technical integration of distributed energy resources – Improving DER capabilities to benefit consumers and the power system*, April 2019, pp. 58-59.

119 For more information, see: https://www.aemc.gov.au/energy-systemelectricity/network-planning.

120 Ibid.

121 For an example of this, see Citipower PowerCor, Australia United Energy, *Enabling rooftop solar exports – Options paper for consultation*, April 2019.

122 The Network Opportunity Maps can be accessed via a web portal: ENA, 'Accessing the Network Opportunity Maps', viewed 26 August 2019, https://www.energynetworks.com.au/accessing-network-opportunity-maps.

123 University of Technology Sydney, 4 July 2019, 'Network Opportunity Maps', viewed 26 August 2019, https://www.uts.edu.au/research-and-teaching/our-research/institute-sustainable-futures/our-research/energy-and-climate-9.

demand period for each area, as these peak periods are the main drivers of additional network augmentation, the costs of which are borne by consumers.

While the maps are a useful addition to the information available to consumers, they currently do not provide information that is detailed enough for consumers with DER to use in order to determine when and how they could maximise the benefits of their specific DER at any given time.

The Commission intends to work with consumers to improve our understanding of consumer information needs, including the role of third party product or service providers. The Commission will, if required, assist consumer groups to progress any regulatory changes to support the provision of necessary information.

4.4.6 ARENA projects

The Australian Renewable Energy Agency (ARENA) has supported a number of integration studies by DNSPs, universities and other interested parties developing new ways of using DER in distribution networks. Information on and data from the projects are published as part of ARENA's Knowledge Bank.[124]

Projects have touched on DER's role in virtual power plants, network support, demand response, microgrids and peer-to-peer electricity trading. Other ARENA-funded projects have been focussed on improving real-time and forecast information of the operational conditions of the distribution network to help DNSPs to operate these networks more efficiently using the DER that is connected to them.

ARENA's projects, and in particular the knowledge sharing from those projects, provides an invaluable source of information for the development of DER hosting arrangements. The Bruny Island battery trial is an excellent example.[125]

BOX 15: **BRUNY ISLAND BATTERY TRIAL**

The CONSORT Bruny island battery trial was an ARENA funded research project and field trial to examine how consumer batteries, in conjunction with solar panels could be used by households to manage their energy usage and costs, and could also be contracted by distribution networks to help manage supply adequacy and reliability.

Battery systems, jointly funded by consumers and ARENA, were used as part of the trial. Each battery system was accompanied by a smart controller that used its own algorithm to plan the dispatch of battery stored energy. The algorithm was designed to minimise the associated home's electricity bill.

The smart controllers, which were connected to the consumer batteries, would coordinate

124 ARENA's Knowledge Bank can be accessed via ARENA, 'Knowledge Bank', viewed 26 August 2019, https://arena.gov.au/knowledge-bank/.

125 Sylvie Thiebaux et al, *Consort Bruny Island Battery Trial – Project Final Report, Project Results and Lessons Learnt*, April 2019, p. 4, 16.

with a Network Aware Coordination (NAC) platform in order to keep the network within its congestion and technical limits. The NAC provided real-time cost-reflective price signals to the consumers' energy management systems, and decisions on providing network support using consumer batteries were made on this basis.

Consumers were offered incentive payments to help the network reduce congestion during times of high demand. Consumers generally saved money from participation in this trial; total energy savings from all installed system sources ranged from $630 up to $1550 per year, with an average participant saving $1100.

ARENA is also funding projects looking at ways to reform distribution networks across the NEM to optimise the benefits to consumers from DER. All the DNSPs in the NEM have been involved in at least one DER related ARENA-funded project.

4.4.7 Consumer prices

Consumer prices provide another useful information source that could help consumers to determine ways to maximise the value they can obtain from DER. Consumers can obtain price information through their electricity bills. Cost reflective prices are an important source of information, clearly signalling where investments and supportive behaviour is most beneficial. More details on the use of pricing reform to provide this information for consumers are provided in Chapter 2.

5 MAINTAINING SECURITY AND RELIABILITY OF THE NETWORK

Distributed energy resources can impact the way that the electricity supply system behaves. In order to maximise participation and the value that can be derived from DER it should behave predictably and, where possible, actively support system security and reliability outcomes.

This chapter discusses issues that, if not addressed, may constrain the degree to which DER can participate in the provision of services to the broader electricity supply system. In particular, a high proportion of variable renewable energy (VRE), such as solar, can cause issues for power systems as a whole, which need to be managed.[126] Facilitating DER participation adds value to both DER owners through access to potential revenue streams, and to other consumers through increased competition in service provision.

In order to fully participate and add most value, DER needs to be well configured and capable fo operating predictably, safely and reliably. Legacy settings and non-compliance with technical requirements mean that the supply system is more vulnerable than it needs to be, meaning that it will have to be operated more conservatively, adding unnecessary costs for consumers. It is important that compliance schemes are reviewed and, where necessary, enhanced as a matter of urgency so that these costs are minimised.

Improvements to DER configuration requirements are also proposed, though amendments to Australian Standards. The sooner these improvements are made, the sooner benefits will flow.

In the long term, a move from synchronous generation like coal and gas fired turbines to asynchronous energy sources like solar panels and batteries may provide opportunities to fundamentally change the way electricity systems are configured and operated.[127]

5.1 Predictability of performance

Distributed generation may disconnect during a system disturbance, potentially at the very time when its output is most needed, and may not recover expeditiously. Like all electrical equipment, domestic inverters that connect distributed generation to the network have finite operating ranges, and must disconnect if they would otherwise suffer damage. However, a number of factors are leading to unpredictable inverter performance, and to a performance that is less robust than it could otherwise be during a disturbance. These factors include:

- standards
- compliance
- waveform issues.

126 See for example AEMO and Electranet, *Update to renewable energy integration in South Australia*, February 2016.

127 See appendix E

Recent evidence suggests that some solar installations are less robust to disturbances than they could be, potentially due to a combination of some inverters not performing in accordance with the standards that they were designed to meet, of incorrect settings being applied to those inverters, and of required settings being sub-optimal. These issues are discussed below.

5.1.1 Compliance

According to AEMO:[128]

> *the observed behaviour of DER during disturbances indicates that a small portion of devices may not be compliant with the existing standards. Methods for measuring and improving compliance need to be explored. This encompasses installation procedures, device certification and testing, enablement of standard functionality with appropriate default settings, and validation of actual performance*.

This lack of compliance, coupled with the diversity of installed equipment, makes it even harder to predict how inverters will perform during network disturbances. Again according to AEMO:[129]

> *Due to the absence of monitoring, the multitude of installed systems and variety in installed devices, it is difficult to collect information on DER and load behaviour during disturbances. This makes it challenging to develop suitable dynamic models that accurately represent DER behaviour, limiting AEMO's ability to diagnose challenges and likely necessitating future conservatism in the implementation of operational constraints. Improved monitoring systems, automated collection and warehousing of device settings, and ongoing processes for updating and adapting models need to be implemented*.

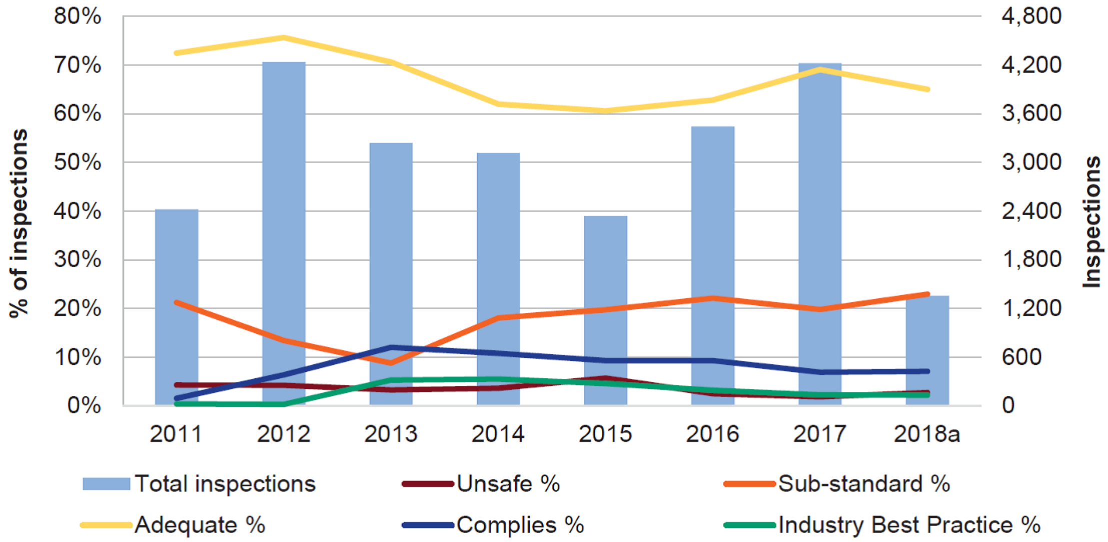
Non-compliance appears to be broader than just inverter settings. The Auditor General noted that over the period 2011 to 2015 between 1.9% and 4.2% of solar PV installations were found to be unsafe, while between 21.7% and 25.7% of installations were found to be either unsafe or substandard.[130]

128 AEMO, *Technical Integration of Distributed Energy Resources, Improving DER capabilities to benefit consumers and the power system A report and consultation paper*, April 2019, p. 5.

129 AEMO, *Technical Integration of Distributed Energy Resources, Improving DER capabilities to benefit consumers and the power system A report and consultation paper*, April 2019, p. 5.

130 Australian National Audit Office, *Auditor-General Report No.18, 2018–19 Performance Audit, Administration of the Renewable Energy Target - Clean Energy Regulator*, December 2018, pp. 49-50.

Figure 5.1: Distribution of inspection ratings over time: 2011 to mid-August 2018



Source: Australian National Audit Office, from the Clean Energy Regulator. See Australian National Audit Office, *Administration of the Renewable Energy Target - Clean Energy Regulator*, December 2018, p. 50.

Note: a - inspections to mid-August 2018

The Clean Energy Regulator (CER) administers the renewable energy target, including the small scale renewable energy scheme (SRES). The SRES creates a financial incentive for individuals and small businesses to install eligible small-scale renewable energy systems, including solar panel systems.[131]

In order to participate in the SRES an installation must, among other things:

- meet relevant Australian and New Zealand standards
- use a Clean Energy Council accredited designer and installer and meet the Clean Energy Council design and install guidelines
- comply with all local, state, territory and federal requirements, including electrical safety.

Installers must provide the CER with signed documents which certify compliance with the installation requirements.[132]

The CER is required to arrange inspections of a statistically significant selection of small generation units that are installed each year for conformance with Australian standards and any other relevant requirements. Compliance failures must be communicated to the state, territory or Commonwealth authorities responsible for enforcement and administration of the standards.[133]

131 It does this through the creation of small-scale technology certificates which Renewable Energy Target liable entities have a legal obligation to buy and surrender to the Clean Energy Regulator on a quarterly basis. Small-scale technology certificates are provided 'up front' for the systems' expected power generation from the installation year until 2030 when the scheme ends. See http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/How-the-scheme-works/Small-scale-Renewable-Energy-Scheme, viewed 13 September 2019.

132 Section 20AC of the Renewable Energy (Electricity) Regulations 2001.

133 Section 23AAA of the Renewable Energy (Electricity) Act 2000 and Part 7 of the Renewable Energy (Electricity) Regulations 2001.

The CER has agreed to the Auditor General's recommendation that it assess the extent to which its Renewable Energy Target scheme data shows any residual systemic electrical safety risks for small generation units installed under the scheme and inform those stakeholders in the best position to effect further treatments.[134] While this address safety risks, it does not necessarily address the performance issues identified by AEMO.

Further, while the CER administered scheme provide a mechanism for managing and enforcing compliance of DER installations that participate in the SRES, not all DER participates. For example standalone batteries, which don't generate renewable energy, are not eligible to participate in the SRES, meaning that not all DER is subject to the CER's inspection and enforcement regime.[135]

The cost of identifying and rectifying non-compliant installations and the risk to the electricity supply system caused by poor technical compliance rates is likely to be much higher than the cost of implementing and enforcing compliance schemes that provide confidence that installations are compliant on they day that they are commissioned. Given the DER installation rate it is important that jurisdictional compliance schemes are reviewed and, where necessary, enhanced as a matter of urgency. In parallel consideration should be given to developing mechanisms to assess the extent of existing non-compliance, and to address existing non-compliance where necessary.

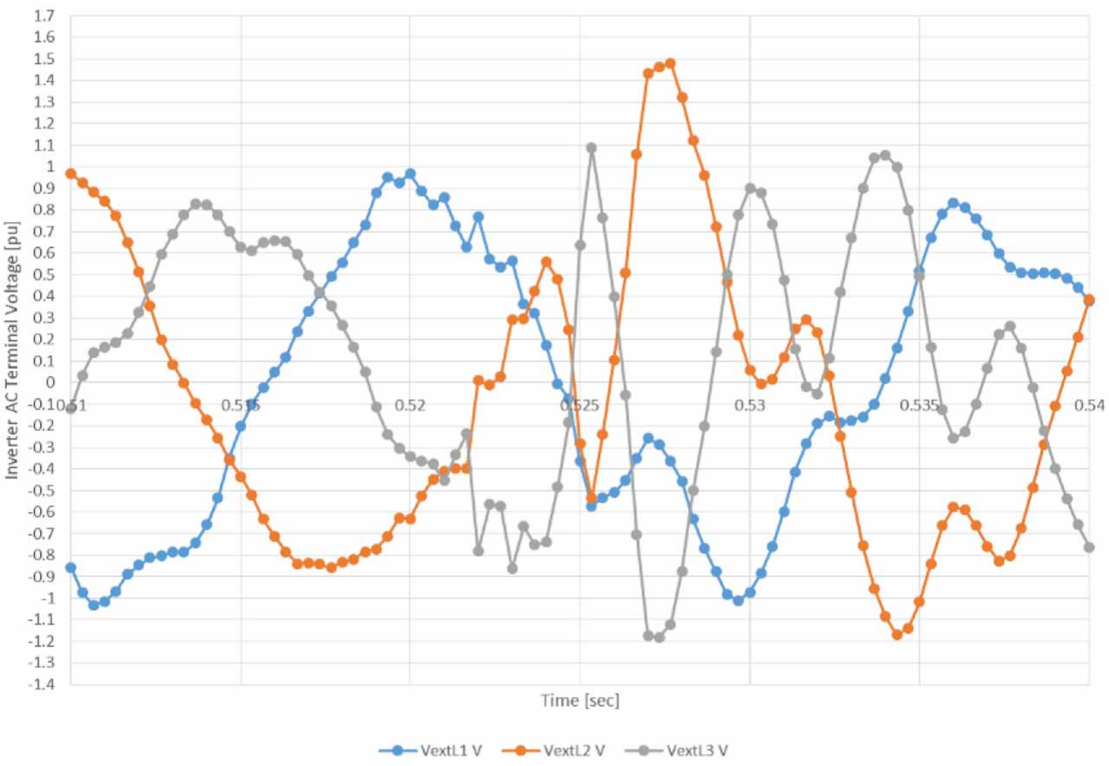
5.1.2 Disturbances

Domestic solar cells and batteries are both direct current devices that have to be connected through inverters to the local low voltage network. Low voltage network waveforms are far noisier than higher voltage network waveforms, making it difficult at times for an inverter to determine voltage magnitudes and frequencies during system disturbances, and to respond appropriately. The figure below shows a distorted low voltage waveforms apparent at the AC terminals of an inverter during a system disturbance. The waveforms correspond to a fire related transmission line fault, which led to a widespread reduction in solar PV generation in California.

134 Australian National Audit Office, Auditor-General Report No. 18, 2018–19 Performance Audit, Administration of the RenewableEnergy Target - Clean Energy Regulator, December 2018, p.11.

135 http://www.cleanenergyregulator.gov.au/RET/How-to-participate-in-the-Renewable-Energy-Target/Choosing-a-system/battery-storage-and-the-small-scale-renewable-energy-scheme, viewed 13 September 2019.

Figure 5.2: LV phase voltages during a transmission fault



Source: North American Electric Reliability Corporation (NERC), *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, *Southern California Event: October 9 2017,* Joint NERC and WECC Staff Report, February 2018, Figure 2.3.

Poor inverter response to the above disturbance resulted in a number of recommendations that should improve inverter performance. Power systems around the world behave similarly, and Australia will benefit from any changes that flow through to international standards.

5.1.3 Improving inverter performance

AEMO has proposed a number of measures, including updates to standards and changes to inverter and protection settings, to improve inverter performance during system disturbances.[136] These measures should improve the ability of inverters to ride through system disturbances, and reduce the level of uncertainty around inverter performance, allowing AEMO to be less conservative when operating the power system, thereby reducing costs to consumers. Pursuant to AEMO's request, Standards Australia commenced a review of AS4777.2 *Grid connection of energy systems via inverters, Part 2: Inverter requirements* on 17 July 2019.[137]

136 AEMO, *Technical Integration of Distributed Energy Resources, Improving DER capabilities to benefit consumers and the power system, A report and consultation paper*, April 2019, Table 1.

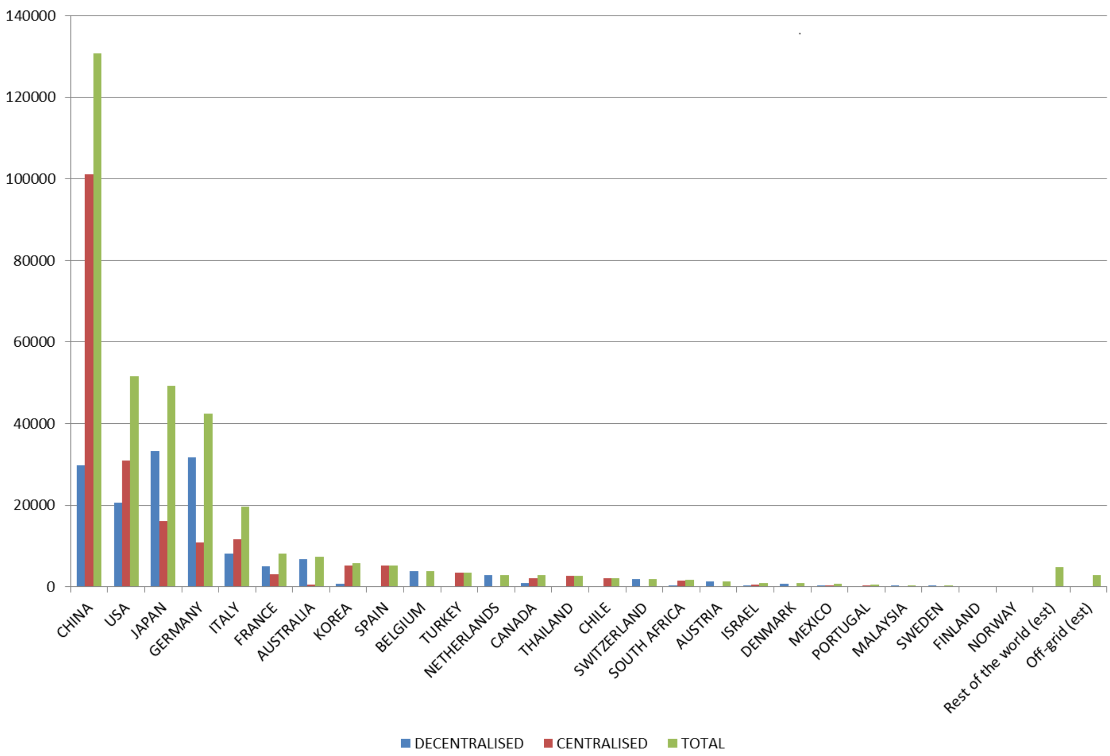
137 Standards Australia, EL-042 Renewable Energy Power Supply Systems, Standards Development Public Portal', viewed 27 August 2019, http://www.sdpp.standards.org.au/ActiveProjects.aspx?SectorName=Electrotechnology%20and%20Energy&CommitteeNumber=EL-042&CommitteeName=Renewable%20Energy%20Power%20Supply%20Systems%20&%20Equipment#simple1.

AEMO has also observed that some active loads such as electric vehicles, which have the potential to contribute to system security, are not currently captured by the performance standards related to other forms of low voltage generation and storage.[138] Best practices standards are required in order for consumers to achieve the maximum possible benefit from managing these loads and potential energy sources. At the very least, characteristics of these loads must be understood in order to properly model system behaviour.

5.2 Standards

While Australia is a world leader in the rate of rooftop solar installations, in absolute terms Australia still makes up a relatively small proportion of the international market for solar PV, as shown below:[139]

Figure 5.3: 2017 cumulative PV capacity by country (MW)



Source: International Energy Agency

Most solar cells and inverters are manufactured overseas. To maximise available markets manufacturers are likely to comply with international, rather than uniquely Australian,

138 AEMO, *Technical Integration of Distributed Energy Resources, Improving DER capabilities to benefit consumers and the power system, A report and consultation paper*, April 2019, p. 5. Note that electric vehicles and charging stations are nonetheless covered by a number of international standards including IEC61851 series, IEC63110 (under development), ISO 15118 and the Open Charge Point Protocol (OCCP).

139 International Energy Agency, *Trends 2018 in photovoltaic applications*, 23rd edition, *Survey Report of Selected IEA Countries between 1992 and 2017*, Photovoltaic power systems programme, Report IEA PVPS T12-34:2018, p.42

standards meaning that Australia needs to work in conjunction with international standards bodies if it wants suppliers to meet its technical needs. Fortunately, while some issues may be emerging earlier in Australia than elsewhere, all power systems with increasing proportions of distributed generation ultimately face the same technical issues, meaning that the technical standards objectives of each country are well aligned.

The International Electrotechnical Commission (IEC) is the key international standard setting body for electricity systems. The IEC has prepared a white paper on stable grid operations in a DER future, which provides recommendations to the IEC community and others.[140] Australia is extensively involved in the development and revision of the IEC's DER related standards.

Australia's membership of international standards committees is managed and approved through a governance structure administered by Standards Australia.[141] Standards Australia also administers the IEC National Committee, which co-ordinates Australia's participation on IEC committees and has a broad membership including regulators, energy networks, manufacturers, governments and accreditation organisations. Australia is currently a participating member of the IEC standards subcommittees on grid integration of renewable energy generation and on decentralised electrical energy systems.[142]

The Australian government provides an allocation of funds, as part of its $4.1 million support for industry service organisations (SISO) program, that supports this work.[143]

Australian / New Zealand Standard 4777.2, *Grid connection of energy systems via inverters - inverter requirements*, heavily references and relies on IEC based standards.

The Institute of Electrical and Electronics Engineers (IEEE), based in the USA, also publishes standards that are adopted internationally, and that manufacturers seek to comply with. Better use of the inherent inverter capability that is becoming available through the recently revised US standard for DER connection, IEEE 1547-2018, also offers opportunities to improve the resilience and performance of inverters and associated distributed generation during disturbances.[144]

AEMO "is investigating best practice international standards such as IEEE 1547-2018, relevant IEC standards, and standards applied in European jurisdictions (most notably Germany and Denmark)."[145]

5.2.1 Interoperability

Interoperability issues are important and clearly need to be appropriately managed. However, it is not yet clear how deeply interoperability and communication protocols should be

140 IEC, White paper, *Stable grid operations in a future of distributed electric power*, 2018.

141 Standards Australia, Standardisation guide 015: Australian involvement in international standardisation, Version: 3.2, Revision 14/02/2019.

142 IEC subcommittees 8A and 8B.

143 Commonwealth Government, *Budget 2019-20, Portfolio budget statements 2019-20 - Budget related paper No. 1.11 - Industry Innovation and Science portfolio*, April 2019, p. 31 and p. 40.

144 AEMO, *Technical Integration of Distributed Energy Resources - Improving DER capabilities to benefit consumers and the power system - A report and consultation paper*, April 2019, p. 5, p. 41 and chapter 3.

145 AEMO, Technical Integration of Distributed Energy Resources, Improving DER capabilities to benefit consumers and the power system, A report and consultation paper, April 2019, p. 46.

specified in mandatory instruments. Interoperability under-reach may allow monopoly capture by proprietary technologies, while over-reach may stifle innovation and development in a rapidly evolving environment. Finding the right balance will require input from a range of stakeholders, including integrators and manufacturers.

International co-ordination is likely to be critical given the relative size of the Australian market. There are already a suite of international standards that apply to DER system communications. By way of illustration, some relevant international standards include:

- IEC 61158 series Industrial communications networks - Fieldbus specifications
- IEC 61850 series Communication networks and systems for power utility automation
- IEC 61968 series Application integration at electric utilities - System interfaces for distribution management
- IEC 61970 series - Energy management system application program interface
- IEC 62056 series - Electricity metering data exchange
- IEC 62325 series - Framework for energy market communications
- IEC 62351 series - Power systems management and associated information exchange - Data and communications security
- IEC 62361 series - Power systems management and associated information exchange - Interoperability in the long term
- ISO 16484 series - Building automation and control systems
- ISO/IEC 14908 series - Information technology - Control network protocol
- IEEE 2030 series Smart grid interoperability.

Australian requirements should exist within this international framework.

AEMO proposes using interoperability provisions for information monitoring of inverters, noting that "remote querying of DER settings, including confirming the standards and settings to which they are programmed are in accordance with network connection agreements, would allow more accurate representation of these systems in AEMO's dynamic models, and therefore allow a less conservative operational approach." AEMO also describes other benefits from the ability to remotely change settings, including the ability to update settings so that they remain optimal in the longer term and in response to dynamic and local conditions, and so that DER can participate more fully in FCAS.[146] While many new inverters, and particularly those associated with batteries, are connected through the internet, the interface with those inverters is provided through suppliers, manufacturers and other third parties. A DER integration API technical working group is also examining data flows and application programming interfaces (APIs) for DER integration.[147]

Clearly the benefits of active communications are also likely to be far greater for installations that contain batteries because batteries can actively participate in both energy and FCAS

146 AEMO, *Technical Integration of Distributed Energy Resources - A report and consultation paper*, April 2019, pp. 57-58.

147 Members include AEMO, AGL, Australian National University, Ausnet Services, Energy Queensland, Greensync, Horizon Power, SA Power Networks and TasNetworks.

markets. For pure solar an installation's energy output is solely dependent on how brightly the sun is shining at the time.[148]

5.2.2 Cyber security

AEMO also notes that "[I]ntroducing the ability to remotely update device settings introduces new cyber security risks, and these will need to be addressed in parallel." Addressing cyber security could be a major issue. Many inverters already have internet communications enabled, with information uploaded to and downloaded from external providers.[149]

The more the power system relies on DER, the more vulnerable it is to cyber-attack targeted at that DER, or targeted at communications linked to it. Cyber security strategies, including potential recovery strategies, will become more important as more communication enabled inverters are rolled out.

An Australian Energy Sector Cyber Security Framework (AESCSF) initiative, led by AEMO, is already underway in response to the Finkel Review recommendation 2.10. The new framework was used to undertake assessments of cyber security maturity across the energy sector, the results of which have been consolidated into the inaugural 2018 report to the Energy Security Board (ESB).[150] This work is at a very early stocktake and self-assessment stage, with all parties recognising that significant further work is required.

5.3 Harmonics

Asynchronous generators can cause network harmonics. Their inverters use switching to generate an approximate sine wave, but the switching itself also generates higher frequency components.[151]

Applicable standards place limits on the harmonics that individual inverters can inject into the network.[152] However, when there are many inverters of the same type or manufacturer connected to a network, the harmonics can add together and cause system current harmonics to flow. Current harmonics cause voltage harmonics which may, if outside of limits, interfere with or otherwise be detrimental to some electrical equipment. Current harmonics also increase network losses through heating.

In the Blacktown solar cities project Endeavour Energy found that, in all case study areas, there was evidence of harmonic current injection into the network, and that harmonic currents were to some extent additive. Fortunately the voltage distortion was not high,

148 To the extent that there are no network constraints.

149 See for example Infinite Energy, 2019, 'Fronius WiFi Monitoring Set Up', viewed 28 August 2019, https://www.infiniteenergy.com.au/support/fronius-wifi-monitoring-set-up/. See also Solar 4 Ever, 'FAQS', viewed 28 August 2019https://www.solar4ever.com.au/FAQ_WIFI.php.

150 AEMO, *2018 Summary Report into the cyber security preparedness of the National and WA Wholesale Electricity Markets - AEMO report to market participants*, December 2018.

151 See for example Faz Rahman, *Lecture 21. Single-phase SPWM inverter switching schemes*, University of New South Wales.

152 International Electrotechnical Commission, IEC 61000-3 series, *Electromagnetic compatibility*, various publication dates.

implying low harmonic impedance. The main concern with the current harmonics was therefore increased losses in the network. [153]

Network businesses continue to be responsible for management of voltage harmonics on their networks, while inverter manufacturers continue producing their inverters to meet international standards. From the limited evidence available, it appears that inverter induced harmonics are not a material issue for network businesses at this stage. Should inverter induced voltage harmonics become an emerging issue as penetration increases, then it may be appropriate to revisit inverter technical standards.

5.4 System stability

Increased distributed VRE penetration potentially raises a number of system security issues. Uncertainty, as discussed in section 5.1, may require system management to be undertaken in a more conservative and therefore more costly manner. However, even without uncertainty, distributed VRE introduces a number of other issues that may require mitigation.

5.4.1 Energy balance

Energy consumed and stored must equal energy produced and released at all times. The intermittency of VRE means that output variation must be 'firmed' by other energy sources, such as synchronous hydro, gas and coal generators, or batteries.

Unlike synchronous generation and batteries, VRE generally has little or no inherent energy storage, meaning that it can't respond to system disturbances that rapidly change the energy balance, such as generator trips or network faults. By contrast synchronous generators store instantly accessible energy in their rotating turbines, coal-fired and CCGT generators store rapidly accessible energy in their boilers in the form of pressure, while batteries can also very rapidly change their output, up to their rated capacity.

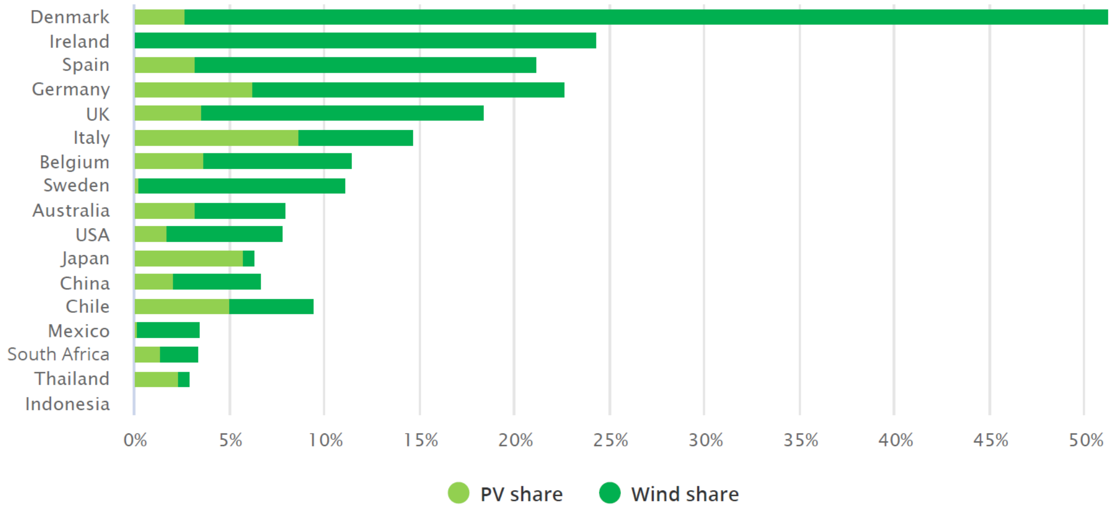
Where total VRE production exceeds consumption, or consumption plus minimum levels of synchronous generation, then a portion of the VRE capacity must be curtailed. Australia's total share of VRE is substantially lower than some countries, as shown below.[154] However, the VRE is not evenly spread. The high penetration of VRE, and in particular wind, in South Australia has at times meant that some large scale semi-scheduled VRE has been turned off and has also meant that additional support, in the form of synchronous condensers, has to be installed.[155]

153 S. J. Lewis, *Analysis and Management of the Impacts of a High Penetration of Photovoltaic Systems in an Electricity Distribution Network*, 2011 IEEE PES Innovative Smart Grid Technologies, November 2011.

154 IEA, 'System integration of renewables', viewed 28 August 2019, https://www.iea.org/topics/renewables/systemintegration/ .

155 ElectraNet, *Addressing the system strength gap in SA - Economic Evaluation Report*, February 2019.

Figure 5.4: Share of variable renewables in electricity generation in 2017 (selected countries)



Source: IEA

AEMO has observed that, in periods when distributed PV contributes a large percentage of regional generation, it may no longer be possible to reduce interconnector flows as required under present operational practice during periods of forced outages, bushfires, or other emergency conditions. While commissioning a new SA-NSW interconnector will be helpful, AEMO is concerned that some intra-regional dispatchability issues may subsequently emerge, citing Port Lincoln as an example.[156]

A form of distributed generation export management may be cost effective in these locations. The form that this management could take could range from controlled generation circuits analogous to existing controlled load circuits, where inverters could be disconnected, or more subtle intervention through aggregators or retailers via inverter control. Energy Networks Australia and the CSIRO identified real time communication and control as one of the post 2023 implementation steps as part of their electricity network transformation roadmap April 2017.[157]

5.4.2 System restart load

AEMO has also raised a potential concern about the impact of VRE on system restart services that are currently provided by large, synchronous generators. While further analysis is required, AEMO has observed that an adequate source of stable load is required to meet the

156 Open Energy Networks Project: ENA and AEMO, *Workshop to test required capabilities, test interactive meta-models and discuss CBA methodology*, March 2019, slide 125.

157 ENA and CSIRO, Electricity network transformation roadmap, final report, April 2017 p.13.

minimum loading requirements of these generators during a black start. Distributed PV reduces the amount of stable load available during daylight hours.[158]

5.4.3 Under-frequency load shedding

The usefulness of under-frequency load shedding, where blocks of customers are automatically disconnected in order to restore system balance when there is insufficient generation, can also be undermined when the those blocks of customers are exporting energy, or have little net load. Similarly, black start restoration may be more challenging if generation is being progressively matched with load, but where that load turns out to be additional variable generation.[159]

The Commission's system security and reliability action plan includes an examination of frequency control, through design work being undertaken in conjunction with AEMO and the AER.[160]

158 Open Energy Networks Project: ENA and AEMO, *Workshop to test required capabilities, test interactive meta-models and discuss CBA methodology*, March 2019, slide 125.

159 Open Energy Networks Project: ENA and AEMO, *Workshop to test required capabilities, test interactive meta-models and discuss CBA methodology*, March 2019, slide 125.

160 AEMC, *System security and reliability action plan 2019 - Updated 15 August 2019*, August 2019.

6 CONSUMER ENGAGEMENT

Distributed energy resources are enabling customers to make decisions about how and when they consume and export electricity. Consumers can use distributed energy resources to reduce their energy costs through a range of actions – including managing their demand, reducing their reliance on the grid, maximising the value of their solar PV system, providing back-up supply or arbitraging their retail tariff.

Such consumer choices should drive the transformation of the energy sector. It is therefore increasingly important for consumer views, preferences and priorities to be reflected in network proposals and regulatory outcomes.

There has been a major cultural change in the sector, which is timely. The Commission observes that network distribution businesses have made significant improvements to the way in which they engage with consumers in recent years. Australian Energy Regulator (AER) network revenue determination processes have become less adversarial, which creates an environment that promotes positive and constructive engagement. This can be partly attributed to the removal of limited merits review in late 2017, separation of the rate of return component of decisions in late 2018, and the AER's ongoing efforts to encourage networks to submit proposals that are underpinned by effective engagement and capable of being readily accepted.[161]

Further, the AER is exploring and applying to an extent negotiated-settlement approaches between consumer representatives and the network businesses. Such developments may play an important role in the transformation of the sector by enhancing consumer engagement. But some stakeholders have raised concerns about whether there are adequate resources for consumers to participate in regulatory processes in this way, and maintain there are significant barriers to consumer engagement. The Commission will continue to closely observe these consumer engagement developments.

6.1 Consumer engagement developments

The Commission introduced requirements for network businesses to better engage with consumers in 2012. In particular, the rules require the AER to consider the extent to which proposed expenditure addresses concerns identified by customers during the network businesses' engagement processes.[162]

To support these reforms, the AER set out its expectations for network businesses to better engage with consumers in its August 2013 Consumer engagement guideline:[163]

> We do not want consumer engagement to become a compliance activity, because that would undermine the potential for engagement to be innovative and responsive to consumers. Instead, we seek a transformation to the way service providers do

161 AER Board member, Cristina Cifuentes, Speech: 'Engagement and energy regulation in a dynamic environment', 4 August 2016.

162 See clauses 6.5.6(e)(5A) and cl. 6.5.7(e)(5A) of the NER.

163 AER, *Consumer Engagement Guideline for Network Service Providers - Explanatory statement*, November 2013, p. 13.

> business. We seek cultural change that results in continual and self-perpetuating improvement to service providers' consumer engagement.

The AER acknowledged in its 2013 guideline that network businesses needed some time to develop and implement robust and comprehensive engagement strategies and approaches.

Building on the AER's guideline, Energy Networks Australia partnered with CSIRO (as part of its Network Transformation Roadmap project) to develop the 2016 Customer Engagement Handbook. The Handbook was designed to provide practical guidance to energy network businesses in fostering transparent dialogue with their customers. It was recognised that engagement practice and expertise will evolve over time, and there is important ongoing work that should take place between all participants in the energy system to share experience and expertise.

Now, as part of the current round of revenue determinations, network businesses are broadly demonstrating a commitment to ongoing and genuine consumer engagement. Network businesses are becoming increasingly willing to innovate and experiment with different consumer engagement approaches, demonstrating cultural change. Industry awards for consumer engagement and innovation have created strong incentives and rivalry among businesses. Across all jurisdictions, the AER has reported significant improvements to the way in which network businesses are engaging with their end-customers – albeit, coming off a 'low base' (see Appendix D for examples).

The AER states:[164]

> We are encouraged by the increasing number of network service providers that are devoting more resources to their respective consumer engagement programs, including greater emphasis on 'deep dive' workshops as part of their pre-lodgement engagement initiatives. Another positive development is the commitment of several network service providers to maintaining an open and ongoing dialogue with stakeholders throughout the regulatory control period, as opposed to engaging intensively once every five years when a regulatory proposal is being considered. By keeping the conversation going, constructive discussions around key and contentious issues could be had well before a regulatory proposal is finalised and submitted to us, with further possible refinements aired as part of our subsequent public consultation processes.

6.1.1 Examples of network innovation and experimentation

AusNet Services trial of New Reg Process

AusNet Services is undertaking a trial of the New Reg Process to engage with consumers. The AER, Energy Consumers Australia and Energy Networks Australia are working together to develop an alternative approach to network regulation within the current regulatory framework.

164 AER, *Ausgrid distribution determination 2019–24, Final decision: Overview*, April 2019, p. 11.

The main idea of the New Reg Process is that consumers – through a 'Customer Forum' – and the network business can come to an agreement that the revenue proposal reflects consumer perspectives and preferences. The Customer Forum was created to become the 'counterparty' to the business in reaching these agreements. It is equipped to understand consumer views, and to reflect these in a process of 'mutually advantageous discovery' to find better outcomes for consumers.[165]

The Customer Forum is expected to evidence how any agreement reflects consumers' preferences, citing relevant customer research and results of consumer engagement. That is, the Customer Forum acts on behalf of AusNet Services' customers based objectively on its consultation and research of consumer views and preferences.

The New Reg Process has two main components:

1. The development of the regulatory proposal through an Early Engagement Process – this Process extends consumer involvement beyond current engagement processes to a point where the network business reaches agreement on some or all aspects of the regulatory proposal.
2. The assessment of the regulatory proposal by the AER – including having regard to areas of agreement (or otherwise) between consumers and the network through the Early Engagement Process, with the reasoning and evidence for this agreement set out in the Engagement Report.[166]

The design of New Reg includes 'checks' throughout the process to ensure any agreed outcomes between the network business and Customer Forum are in the long term interests of consumers. The AER is integral to the process pre-lodgement of the regulatory proposal and provides support to the Customer Forum. The significant consultation requirements on AER network revenue determination processes prescribed under the NER apply to any trials of New Reg. The New Reg Process supplements, rather than replaces, other forms of engagement the AER and networks undertake with consumers and consumer groups.

Cambridge Economic Policy Associates (CEPA), in its evaluation of AusNet Services' trial of the New Reg Process, stated:[167]

> The Customer Forum appears to be providing a good conduit for consumers' perspectives. The Customer Forum has had a positive impact on AusNet Services' customer engagement and identified areas/processes where AusNet Services could improve its services. The Customer Forum has achieved this by working with AusNet Services to engage with a range of different types of customers in different locations.

The Commission is working closely with participants to monitor and consider learnings and outcomes of the trial, including any recommended changes to the rules to better facilitate the New Reg Process.

165 AER, ECA, ENA, *New Reg: Towards consumer-centric energy network regulation - Directions paper*, March 2018, p. 3.
166 AER, ECA, ENA, New *Reg: Towards consumer-centric energy network regulation - Directions paper*, March 2018, p. 4.
167 CEPA, *New Reg: AusNet Services Trial Insights Report 2 – Negotiations Round 1*, May 2019, p. 10.

Jemena's direct engagement with its customers

Some network businesses are taking up the challenge of significant direct engagement with their end customers (supported by consumer representatives) to better reflect consumer views in their regulatory proposals, build trust and support growth of a customer-focus culture.

The Consumer Challenge Panel, which is established to provide input and challenge the AER on key consumer issues during a network determination, observed that Jemena is at the forefront of both development and application of consumer engagement approaches.[168]

Jemena convened a 'People's Panel' of 43 residential customers, with 20 hours spent over six sessions – including field trips – to develop a list of recommendations representing customer views. The list includes actions within Jemena's direct control and issues that Jemena should advocate for on behalf of its customers. Most of the sessions were observed by representatives from the Consumer Challenge Panel and/or the AER.

The People's Panel's 25 recommendations have influenced Jemena's regulatory proposal:[169]

> After reviewing each [recommendation] for ease and cost of implementation, we have committed to adopt every one of the recommendations. In line with the first strategic goal for the engagement process, these recommendations have shaped our draft Plan.

Jemena, reflecting on its consultation process, said:[170]

> The panel process delivered us much more than we initially expected. Yes, customers voted, and we were presented with a set of recommendations but, even more than that, we obtained deep insights into how customers feel, their values, and what drives their decisions. … What struck us throughout our People's Panel process was how community-minded customers were. We found that while the affordability of electricity was a primary concern for all members of the community, the panel were also very keen to push towards a 'greener' grid.

6.1.2 Benchmarking consumer engagement

Energy Networks Australia introduced industry awards in 2017 to recognise leadership in consumer engagement by network businesses. The judging panel includes the CEOs of both Energy Consumers Australia and (starting in 2019) the Commission, an AER Board member, and a range of consumer representatives. The judging panel considers how consumer engagement by a network business achieved: accessibility, inclusiveness, responsiveness and transparency, 'measurability', and 'leadership'.

The Commission considers Energy Networks Australia's initiative has helped to build knowledge of successful engagement approaches, and creates reputational incentives and rivalry among the businesses.

168 Consumer Challenge Panel, Sub-Panel CCP17, *Progress Report on Consumer Engagement by the Victorian Electricity Distribution Businesses for the 2021-2025 Regulatory Reset*, March 2019, pp. 11–15.

169 Jemena, *Jemena Electricity Networks - Draft 2021–25 Plan*, January 2019, p. 22.

170 Jemena, *Jemena Electricity Networks - Draft 2021–25 Plan*, January 2019, p. iii and p. 18.

The winner of the 2019 Annual Award for consumer engagement is Jemena for its Gas Networks Deliberative Forum in NSW as well as its People's Panel citizens' jury in Victoria (as highlighted above). In awarding Jemena, the CEO of Energy Consumers Australia said:[171]

> Initiatives like Jemena's, to make engagement opportunities accessible and inclusive with translators, child care assistance, transport services and in-language consultation, shows strong progress and we look forward to these approaches becoming the norm.

The winner of the 2018 Annual Award for consumer engagement was Essential Energy, for the extensive engagement described in section Appendix D. The other finalists included SA Power Networks and the five Victorian distributors as part of a joint consultation process (AusNet Services, CitiPower, Jemena, Powercor and United Energy).

6.2 A more positive and constructive engagement environment

The environment of network revenue determination processes has changed markedly in recent years, with increasingly positive and constructive engagement by the AER, networks and consumers on regulatory processes. This helps smooth the transition to a future consumer-centric electricity system and enable consumers to engage with energy markets in new and exciting ways.

The limited merits review regime, the appeals process that enabled networks to challenge AER determinations on allowable network revenues, was removed in late 2017. The AER Chair stated the limited merits review process produced a more adversarial relationship between the regulator and regulated entities[172]:

> In the past our engagement with network businesses has been driven, in part, by the existence of Limited Merits Review (and businesses' interest in engaging with Limited Merits Review). This led to a more adversarial relationship. … but the removal of the review process means a change of approach by all is inevitable. That change can and should result in a more transparent and positive interaction between the market, the regulator and that most important component of the jigsaw, the consumer. … We are already seeing some network businesses responding to the need to vary their approach to stakeholder engagement. Many are now proactively engaging consumers in their regulatory process and reaping the rewards.

Further, in December 2018, the National Electricity Law (NEL) and the National Gas Law (NGL) were amended to require the AER to make a binding rate of return instrument – which sets out the methodology for calculating the rate of return. This separation of the rate of return decision has also made revenue determination processes less adversarial. The rate of return was the most contentious part of these decisions – estimation is highly complex and it is the most significant driver of network revenue. Indeed, previous appeals to the Australian Competition Tribunal largely related to the rate of return calculation.

171 See: https://www.energynetworks.com.au/sites/default/files/091309_energy_network_annual_award_winners_announced.pdf

172 AER Chair, Paula Conboy, Speech: 'Working together to restore confidence in energy regulation', 26 July 2017. See also AER, *Working together to restore confidence in energy regulation*, media release, 26 July 2017.

The AER is actively promoting early engagement to incentivise more 'robust' expenditure proposals. Network businesses now commonly develop and consult on 'draft plans' before submitting their regulatory proposals to the AER. Australian Gas Networks, ElectraNet and TasNetworks paved the way.[173] As a result, AER regulatory processes have become more open to constructive dialogue between consumers and the network businesses, as highlighted in Appendix D. This has led to the AER broadly accepting regulatory proposals in some cases.

The AER Chair stated:[174]

> In a world without limited merits review, everyone needs to engage earlier in the regulatory process so that we can resolve key points of disagreement between stakeholders. … Our goal is to incentivise and reward well-evidenced, transparent and reasonably costed regulatory proposals. Further, this process could save consumers, the businesses and the AER significant resources, and promote greater regulatory predictability.
>
> By entering into discussions with the networks and bringing consumers to the table at an earlier stage when the networks are developing their proposals, we are really getting better outcomes in terms of prices and in terms of trying to understand where the other person is coming from.

Further, the AER is exploring negotiated-settlement approaches through New Reg (discussed above). The process being trialled involves the establishment of a Customer Forum to be the 'formal counterparty' in negotiations with the network business and to, as far as possible, reach agreement on the regulatory proposal prior to its submission.[175] In a recent speech, the AER Chair said:[176]

> I trust that the New Reg process is a sign of things to come. This is a big step in the right direction to improve trust between consumers and network businesses - trust that needs to be rebuilt and is vital in ensuring the transformation of the sector happens in a way that delivers positive outcomes for consumers, businesses and the community more widely.

The AER facilitated 'negotiated outcomes' between consumer representatives and the ACT/NSW distributors to resolve all outstanding issues remitted to the AER by the Australian Competition Tribunal, as part of the AER's August 2018 decisions. This approach allowed the AER to effectively manage the 'novel circumstances' of the process – putting an end to ongoing and complicated disputes. The AER Chair said:[177]

173 AER Chair, Paula Conboy, 'Working together to restore confidence in energy regulation', 26 July 2017.

174 Ibid. See also Ben Potter, 8 February 2019, 'Paula Conboy won't seek second term as Australian Energy Regulator chair', viewed 28 August 2019, https://www.afr.com/politics/paula-conboy-wont-seek-second-term-as-australian-energy-regulator-chair-20190208-h1b0xs.

175 AER, ECA, ENA, *New Reg: Towards consumer-centric energy network regulation - Directions paper*, March 2018, p. 10.

176 AER Chair, Paula Conboy, Speech: '*Looking back and looking forward - an AER Chair perspective*', 31 July 2019.

177 Ibid.

> *Out of the adversity of the appeal process, came efforts to deliver more constructive regulatory processes that better engaged consumers. The NSW/ACT businesses worked with consumer groups to understand their preferences and expectations and together they arrived at outcomes that were timely and capable of acceptance by all parties.*

At the conclusion of these remittal processes, the AER Chair stated:[178]

> This outcome is a great example of how engaging with consumers in a revenue setting process can benefit everyone, and it's a process being applied more broadly to other network decisions. This is the type of approach the AER is keen to model with network businesses to drive a more efficient reset process across the National Energy Market.

The Consumer Challenge Panel (CCP) is similarly promoting negotiated settlement-type approaches:[179]

> The CCP aims to work on the basis of 'no surprises', which means that it is proactive in identifying emerging issues or concerns, and bringing them to the early attention of the businesses and the AER. … The CCP has a goal that the regulatory proposals are 'capable of being accepted' when lodged. This report is intended to provide an opportunity for the distribution businesses to consider their engagement to date, with the intention that the proposals, when complete, will as much as possible reflect a high standard of interaction with consumers that is transparent, balanced, extensive and effective.

6.3 Barriers to consumer engagement

It is widely acknowledged that there are significant barriers to effective consumer engagement in regulatory processes, despite the developments described above. AER revenue determinations are complex. For example, the expenditure assessment-related rules constraining AER decisions include multiple layers of objectives – comprising separate capex and opex objectives, capex and opex expenditure criteria, and capex and opex factors, in addition to the overarching NEO and Revenue and Pricing Principles. This detail is very challenging for stakeholders.

The AER previously commented that consumer groups have limited resources to engage in regulatory processes, especially given their competing priorities:[180]

> Consumers have generally found it difficult to maintain the level of engagement required to make a major impact on all aspects of these regulatory decisions. This requires a significant investment of resources, and consumers have competing priorities and sometimes very limited resources.

178 AER, *Consumers win from AER decision on Ausgrid revenue*, media release, 24 January 2019.

179 Consumer Challenge Panel, Sub-Panel CCP17, *Progress Report on Consumer Engagement by the Victorian Electricity Distribution Businesses for the 2021-2025 Regulatory Reset*, March 2019, p. 3.

180 AER submission to COAG Energy Council consultation paper on consumer engagement, November 2017, p. 1.

Moreover, as the Public Interest Advocacy Centre previously submitted:[181]

> The lack of resources to participate in processes, overcome complexity, provide sound evidence and balance the weight of material presented by network businesses remains the biggest barrier to consumer engagement. … Without a specific increase in consumer funding for participation in network determination processes, it is likely that both the AER's determinations and any subsequent administrative reviews will continue to produce results that are heavily weighted towards network businesses, to the detriment of consumers.

In its submission to this review, the South Australian Council of Social Service (SACOSS) highlighted that consumer groups are broadly finding it challenging to engage on important policy discussions, especially given limited consumer resources with many competing priorities:[182]

> … this is of particular concern given consumer choices (consumer empowerment) are what is driving the major developments of the energy market and the overall test is the long term interests of consumers. Such barriers to consumer engagement, whereby consumer views and preferences are not fully understood and taken into account in regulatory processes, may undermine energy market developments.

Further, SACOSS states:[183]

> … the current regulatory framework is relatively robust however: Limited Merits Review, although now abolished, has left a legacy of very conservative regulatory decision making; and the Rules were not designed to facilitate the level of consumer engagement that has developed especially in more recent years. The AER is experimenting with negotiated-settlement type approaches. SACOSS has significant concerns with this approach … A concern is that the regulatory framework does not provide adequate safeguards in the process to ensure decisions are in the long term interests of consumers.

6.4 Forward momentum

Consumer engagement is an exciting area of innovation in Australia, by both regulators and the network businesses. The Commission is encouraged by recent improvements in the way consumer views, preferences and priorities are reflected in network proposals and regulatory outcomes. We expect this trend to continue.

These developments are timely and support the transformation of the sector, whereby consumer adoption of distributed energy resources is causing positive 'disruption' and changing the way network infrastructure is used. Early and meaningful consumer

181 PIAC, Consumer resourcing for participation in revenue determinations, Submission to COAG Energy Council consultation paper on consumer engagement, 6 November 2017, p. 7.

182 SACOSS, Submission to Electricity Network Economic Regulatory Framework Review, 21 March 2019, p. 3.

183 SACOSS, Submission to Electricity Network Economic Regulatory Framework Review, 21 March 2019, p. 1.

engagement – on issues such as tariff structures and investment to address export constraints – is important now more than ever.

The Commission is mindful of stakeholder concerns that significant barriers to effective consumer engagement remain, and negotiated settlement-type approaches require adequate safeguards to protect the long term interests of consumers. The AER should continue to take such issues into account in its regulatory processes. The Commission will monitor developments and consider whether the regulatory framework is keeping pace with evolving AER approaches, including through learnings from the New Reg trial. The COAG Energy Council was considering options to improve resourcing available to consumer groups to support more effective engagement in AER revenue determinations.[184]

6.4.1 Our commitment to promoting consumer engagement

In a rapidly changing environment, the knowledge and expertise of our stakeholders is invaluable. The Commission is very fortunate in this regard; experts across the energy sector – including consumer representatives – willingly dedicate their time to be part of working and technical reference groups; to prepare detailed submissions on complex matters of policy; and to attend forums and workshops. Working with our stakeholders, we consider how changes to one part of the market will affect other parts; how options that weren't available a relatively short time ago may now be possible because of technological advancement or market maturity and how regulatory frameworks can respond to new business models, technologies, and consumer needs.

The Commission is committed to continually improving the quality of our engagement and communications, especially with consumers. We have an ongoing focus on providing clear, accurate and relevant information, using processes and communication channels that make it easy for stakeholders to engage with us. We strongly value consumer insights. Better understanding of consumer views and preferences promotes the objectives of energy sector regulation.

For example, the Commission holds a bi-annual Consumer priorities forum to hear directly from consumer representatives about what they consider to be the key issues, and receive feedback on major projects and consultation processes. Commission staff have attended and presented on the Economic regulatory framework review at both of the National Consumer Roundtable on Energy meetings in 2019.[185] The Commission publishes plain English guides – such as 'Applying the energy market objectives'[186] – and education material through the AEMC's 'Perspectives' staff paper series, which cover market developments and how energy sector reforms can benefit the Australian community.[187] Targeting a broad audience, the

184 COAG Energy Council, 6 October 2017, 'Consumer participation in revenue determinations and associated regulatory processes – Consultation Paper on Consumer Resourcing', viewed 28 August 2019, http://www.coagenergycouncil.gov.au/publications/consumer-participation-revenue-determinations-and-associated-regulatory-processes.

185 SACOSS, 'Roundtable Meetings and Outcomes', viewed 28 August 2019, https://www.sacoss.org.au/roundtable-meetings-and-outcomes.

186 AEMC, *Applying the Energy Market Objectives*, 8 July 2019.

187 See: AEMC, 'Perspectives', viewed 28 August 2019, https://www.aemc.gov.au/news-centre/perspectives.

Commission publishes infographics, fact sheets and information sheets to explain rule changes and market reviews.

7 ONGOING MONITORING OF ROBUSTNESS OF REGULATORY FRAMEWORK

The Commission has consulted on alternative approaches to expenditure assessment and remuneration to address the potential for expenditure bias as part of the 2019 Economic regulatory framework review. If there was evidence of an expenditure bias, it may impact the regulatory framework's ability to continue to support the electricity sector's transformation.

In the future it is expected that there will be a greater substitution possibility between capital expenditure (capex) and operating expenditure (opex) solutions. As discussed in the *2018 Economic regulatory framework review* report, technologies such as DER, grid-scale batteries or pumped hydro can provide a range of services to multiple participants in the energy sector, including services that are valuable to networks to help them manage technical issues on their networks or reduce peak demand. As a result, networks will increasingly be required to make choices on whether to undertake traditional poles and wires capex investments or to use opex to procure alternative services from third parties.[188]

Unbalanced incentives may distort investment decisions where a network service provider chooses a solution that would provide the greatest financial return instead of the most efficient solution. This is not to the benefit of consumers.

The Commission's exploration of alternative models for network incentives and revenue-setting addresses one of the recommendations from the Independent Review into the Future Security of the National Electricity Market (the Finkel Review). The Finkel Review recommended that if the Commission's modelling demonstrates that there is a bias towards capex over opex, the Commission should assess alternative models for network incentives and revenue-setting – including a total expenditure (totex) approach.[189]

7.1 Limited stakeholder support for reform

The modelling and analysis conducted by the Commission as part of the 2018 Economic regulatory framework review showed that the regulatory framework does not necessarily create a clear, systematic bias in favour of either capex or opex, and the financial incentives vary depending on the circumstances. However, in certain circumstances, the Commission found the regulatory framework creates a bias towards capital investments in network assets – particularly when the expected cost of capital is lower than the regulated cost of capital, which increases the financial return of the capex solution. The Commission concluded that such misalignment of incentives is due largely to the current method of separate assessment and remuneration of opex and capex.[190]

To progress the Finkel Review recommendation noted above, the Commission published an Approach paper calling for submissions, and held a public workshop to help identify and understand risks and opportunities for reform. At the workshop, the Commission outlined

188 AEMC, 2018 Economic regulatory framework review, July 2018, pp. vi–vii.

189 Independent Review into the Future Security of the National Electricity Market, June 2017, p. 152, recommendation 6.8.

190 AEMC, 2018 Economic regulatory framework review, July 2018.

possible models for network incentives and revenue-setting – including the pros and cons of alternative approaches to expenditure assessment and remuneration, and experience overseas. Further, presentations were made by the AER, Energy Consumers Australia and Energy Networks Australia.[191]

The Commission received 12 submissions in response to the Approach paper and received feedback at the public workshop, with 50 participants.

In submissions, most stakeholders considered that there was not clear evidence of an expenditure bias and there was limited support for moving to alternative models such as totex – although several stakeholders supported the Commission undertaking further investigation on these issues.

For example, the Network Shareholder Group submitted:[192]

> Providing an explicit financial mechanism or revenue allowance for demand management, or a 'totex' or performance-based regime should increase the incentives for efficient investment and innovation, and we support further investigation of these options.

In the only submission supporting the adoption of a totex approach, the Clean Energy Council states:[193]

> The different treatment of operating and capital expenditure will be impractical and counter-productive in a future with high penetration of distributed solar and energy storage. The CEC supports moves toward assessment of total expenditure.

On the other hand, Energy Consumers Australia submits:[194]

> … significant improvement is possible in the application of economic regulation to electricity networks. … Energy Consumers Australia is not confident that the implementation of any variety of 'totex' approach will significantly enhance the operation of the incentive regime nor provide any benefits in accelerating the transition of networks to supporting and utilizing significantly higher levels of Distributed Energy Resources.

The AER recognised that totex can mitigate against financial drivers of capex bias and diminishes the materiality of differences in capitalisation policies. But the AER raised concerns about the long term implications of disconnecting revenue from capital funding and depreciation from the economic usefulness of the assets.[195]

191 See here: https://www.aemc.gov.au/sites/default/files/2019-04/Public%20workshop%20-%206%20March%202019%20-%202019%20Economic%20regulatory%20framework%20review%20-%20AEMC%20slides.pdf

192 Network Shareholder Group, Submission to AEMC 2019 Economic regulatory framework review, 14 February 2019, p. 2.

193 Clean Energy Council, Submission to AEMC 2019 Economic regulatory framework review, 14 February 2019, p. 1.

194 Energy Consumers Australia, Submission to AEMC 2019 Economic regulatory framework review, 11 April 2019, p. 4; 5.

195 AER, DER and network regulation presentation, 6 March 2019, slides 10-11.

Several stakeholders considered that there was no evidence of an expenditure bias and that accordingly there was not a strong reason for adopting alternative models at this stage. For example, AusNet Services said:[196]

> Importantly, it is not long since measures were put in place to balance incentives through the AER's Better Regulation program, which included the introduction of a capex efficiency sharing scheme (alongside the opex efficiency sharing scheme) and introduction of the demand management incentive scheme. The success of these reforms has yet to be fully tested, but recent capital underspends compared to allowances does not indicate that there is an ongoing bias towards capital solutions.

Similarly, Energy Networks Australia submits:[197]

- The AER's rate of return guideline has reduced the allowed return on equity to the lowest level ever. As such, there may now be incentives to inefficiently substitute opex for capex.
- Consideration of addressing appropriate network incentives should therefore be forward-looking taking into account these circumstances.
- In any case, capex (especially augex) and opex/capex ratio trends 'provide little empirical support for an ongoing systematic capital expenditure bias of a kind that could impact efficient outcomes for consumers.'
- 'This evidence is very clearly inconsistent with the proposition that there is a strong systematic bias towards capital expenditure due to the regulatory framework.'
- 'Rather, the evidence shows that there has been a very pronounced move away from capital expenditure even in the period since the 2013 [Rate of return] Guideline, with the incentives for that move reinforced by the 2018 [Rate of return] guideline.'

Some stakeholders supported moves towards output/performance-based regulation. Others called for a broader review of the regulatory framework. For example, TransGrid states:[198]

> A better approach at this time may be to stand back and look at the big picture, allowing a principles based rethink of the overall arrangements if this is deemed necessary based on a review of the current arrangements.

At the public workshop, the strong view from stakeholders was that there is not currently clear evidence of an expenditure bias, reforms to address the risk of unbalanced incentives were not a priority and there was not significant support for developing alternative models such as totex.

7.1.1 Commission view

Based on this consultation, the Commission does not recommend further progression of reform actions to address unbalanced incentives at this time. As indicated above, there has been very little support by stakeholders to undertake reforms to address concerns about

196 AusNet Services, Submission to AEMC 2019 Economic regulatory framework review, 14 February 2019, p. 2.

197 Energy Networks Australia, Submission to AEMC 2019 Economic regulatory framework review, 14 February 2019.

198 TransGrid, Supplementary submission to AEMC 2019 Economic regulatory framework review, 18 April 2019, p. 4.

unbalanced incentives in submissions to this review. Development of a totex assessment approach is not currently considered a priority issue by stakeholders and would be a significant reform – requiring considerable resources at a time when there are numerous other major reform projects underway by the Commission and others.

The Commission notes the risks of expenditure bias are less in the current environment. Networks have a limited ability to source investment funds at a rate significantly lower than the regulated rate of return given historically low interest rates. Demand for network services is generally flat and capex spending across the sector is at relatively low levels, as shown in Appendix A and highlighted by ENA in its submission.

7.2 Ongoing monitoring

The Commission will continue to closely observe expenditure trends (see Appendix A) and monitor the risk of unbalanced incentives leading to investment bias as part of the annual Economic regulatory framework review.

Although the Commission does not recommend progression of reform actions at this time to address unbalanced incentives, some steps can be taken to develop the robustness and availability of regulatory data that would possibly enable totex-type assessments or other approaches in the future. Further investigation is required to establish the viability of totex benchmarking for Australian networks. For example, a study could be undertaken to consider different totex benchmarking models, and assess whether sufficiently consistent disaggregated opex and capex data could be obtained from the AER's Category Analysis RINs to support the various totex benchmarking approaches.

The AER would be well-placed to undertake this benchmarking study, or it could be undertaken by another organisation and potentially funded through an ARENA project. Nonetheless, the Commission supports the AER's current continuous improvement program of its economic benchmarking techniques, data collection and development of regulatory approaches.[199]

The Commission is open to exploring the potential to shift the overall regulatory framework to a more performance-based form of regulation in the longer term[200] – as suggested by some stakeholders in submissions and at the public workshop. We will continue to consult with stakeholders on such issues and monitor overseas developments. Ofgem's RIIO framework contains a number of output based targets in addition to traditional incentive schemes.[201] The Hawaii Public Utilities Commission is in the process of updating its traditional cost of service approach with a new performance-based regulatory framework.[202]

199 For example, see: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-our-approach-to-forecasting-opex-productivity-growth-for-electricity-distributors

200 This could incorporate performance-based incentives to incentivise networks to best manage network constraints to minimise limitations on customer solar PV exports, as discussed in Chapter 3.

201 AEMC, 2018 Economic regulatory framework review, July 2018, p. 105.

202 See: https://puc.hawaii.gov/wp-content/uploads/2019/05/PBR-Phase-1-DO-3-Page-Summary.05-23-2019.Final_.pdf

ABBREVIATIONS

ACCC	Australian Competition and Consumer Commission
AESCSF	Australian Energy Sector Cyber Security Framework
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
CEPA	Cambridge Economic Policy Associates
CESS	capital expenditure sharing scheme
COAG	Council of Australian Governments
CDR	Consumer data right
COGATI	Coordination of generation and transmission investment
Commission	See AEMC
DAPR	distribution annual planning reports
DER	distributed energy resources
DNSP	distribution network service provider
DRSP	demand response service provider
DSO	distribution system operator
DUOS	distribution use of system
EBSS	efficiency benefit sharing scheme
ENA	Energy Networks Australia
ESB	Energy Security Board
EVs	electric vehicles
FCAS	frequency control ancillary services
GWp	gigawatts peak
ICE	internal combustion engine
IDSO	independent distribution system operator
IEC	International Electrotechnical Commission
IEEE	The Institute of Electrical and Electronics Engineers
kWh	kilowatt-hours
LV	low voltage
MC	metering coordinator
MDP	metering data provider
NAC	network aware connection
NEL	National Electricity Law
NEM	national electricity market
NERC	North American Electric Reliability Corporation

NEO	National electricity objective
NER	National Electricity Rules
NERR	National Energy Retail Rules
NSP	network service provider
OCCP	Open Charge Point Protocol
OpEN	Open Energy Networks
PV	photovoltaic
RAB	regulated asset base
RERT	Reliability and Emergency Reserve Trader
RIN	Regulatory Information Notices
RIT-D	regulatory investment test for distribution
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAPS	stand-alone power system
SCADA	Supervisory control and data acquisition
SCO	Senior Committee of Officials
STPIS	Service Target Performance Incentive Scheme
TNSP	transmission network service provider
VCE	Value of a customer export
VRE	variable renewable energy
VPP	virtual power plant

A KEY PERFORMANCE INDICATORS

> BOX 16: **SUMMARY OF KEY OBSERVATIONS**
>
> - The National Electricity Market (NEM) has recent seen minimal recent growth in the regulated asset base (RAB) of distribution network service providers (DNSPs).
> - DNSP capex has increased slightly over the last year following a sharp decline in capex that has occurred since 2012-13. Much of this increase appears to be replacement expenditure.
> - After plateauing in 2014-15, transmission network service provider (TNSP) RABs have declined in the past year.
> - The average DNSP utilisation rate has increased slightly after a trough in 2014-15.
> - The number of small customer premises with smart meters installed has reached nearly 15% in South Australia and more than 10% in New South Wales and Queensland.

As part of the Electricity network economic framework review, the Commission annually monitors some key performance indicators, particularly for DNSPs and TNSPs.

This year's monitoring update includes network capital investment metrics with a focus on DNSPs. It also includes DNSP network utilisation metrics, reliability, energy delivered and smart meter installation trends for small customers, as well as indicators of the broader investment environment for electricity networks. Unless stated otherwise, all values in this section are in 2018 dollars.[203]

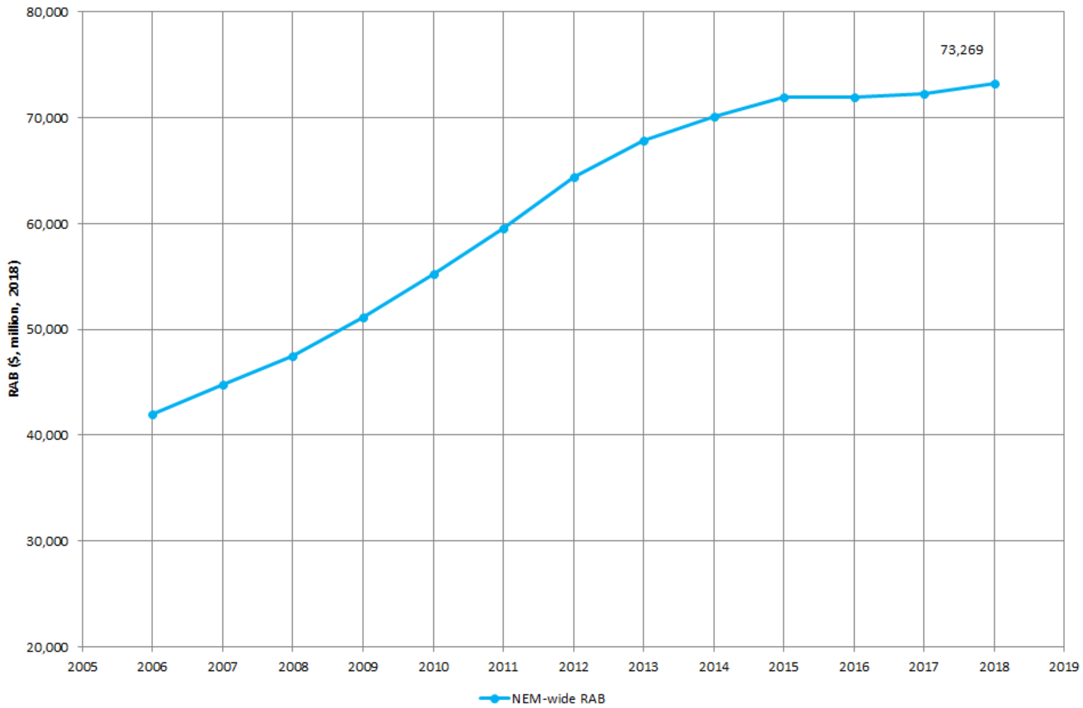
A.1 Investment trends for DNSPs

A.1.1 DNSP RAB trends

Figure A.1 shows the combined closing RAB for all DNSPs in the NEM. The combined RAB experienced significant growth until 2014-15, but has only experienced minimal growth since then, reaching approximately $73 billion.

203 There are differences in Regulatory Information Notices (RIN) reporting times between jurisdictions. Victorian DNSPs report on a calendar year basis, whereas DNSPs in remaining jurisdictions report on financial year basis. The data reported for financial years has been re-aligned to the second half of calendar year i.e. data reported for 2017-18 financial year is represented as 2018 data for the NEM wide analysis.

Figure A.1: Combined closing RAB of DNSPs in the NEM



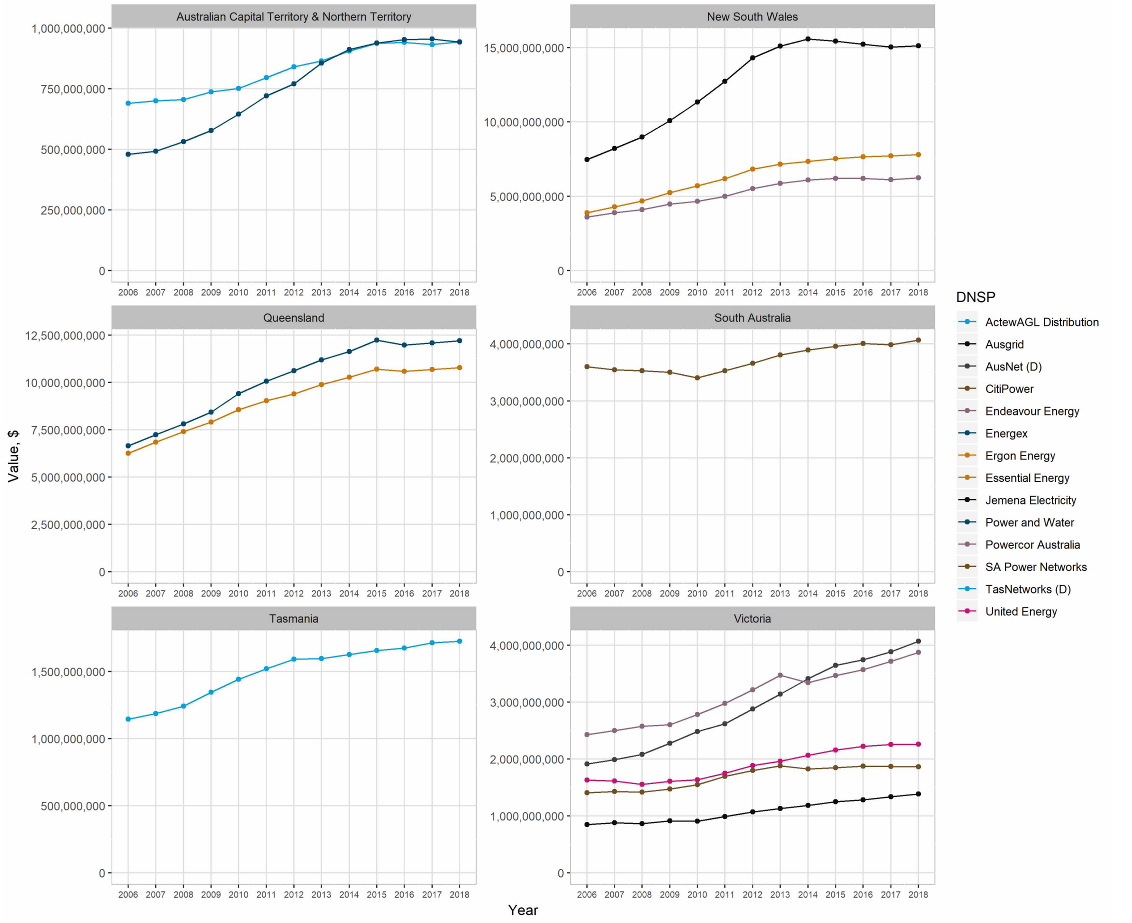
Source: AER
Note: Values in 2018 real dollar terms.

High historical growth of DNSP RABs between 2006 and 2014 has been attributed to factors such as higher reliability standards in Queensland and New South Wales and unrealised forecast demand growth.

DNSPs with spare capacity may have a greater ability to accommodate the rapid uptake of rooftop solar.[204]

204 CitiPower, Powercor Australia, United Energy, *Enabling rooftop solar exports – Options paper for consultation*, April 2019, p. 10.

Figure A.2: DNSP RAB



Source: AER.
Note: Values in 2018 real dollar terms.

Figure A.2 shows the RAB for every DNSP in the NEM across the reporting periods. It shows rapid growth in RABs until 2014-15, particularly for Ausgrid, Ergon Energy and Energex. Notable increases in RABs also occurred during this time for Power & Water, TasNetworks distribution and Victoria's larger regional-serving DNSPs (Powercor Australia and AusNet distribution).

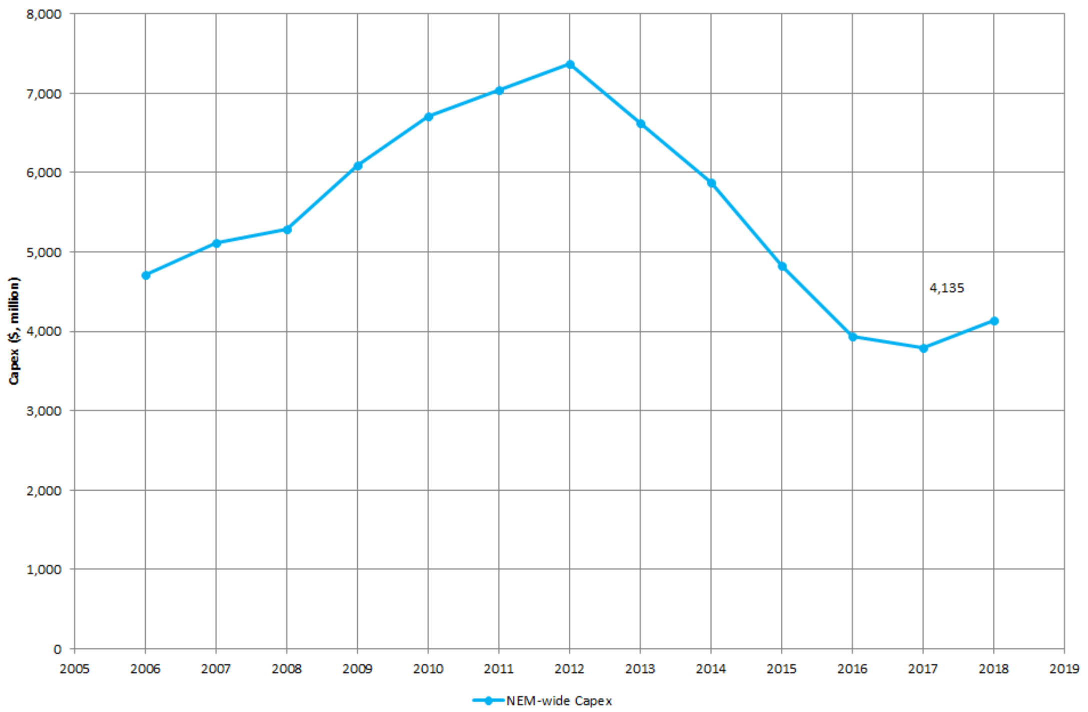
From 2014-15 RAB growths have been more subdued, with the exceptions of Powercor and AusNet. The slowing of RAB growth could reflect a combination of factors, including lower rates of return, weaker electricity demand, greater uncertainty, operating efficiencies implemented by network businesses and regulatory refinements such as the Australian Energy Regulator's (AER's) wider use of benchmarking.[205]

205 AER, *State of the Energy Market 2018*, May 2018, p. 152

A.1.2 DNSP capex trends

Capex (capital expenditure) adds to a network service provider (NSP)'s RAB. The recent flattening of RABS above corresponds to lower capital spending, as shown below.

Figure A.3: Combined DNSP Capex in the NEM

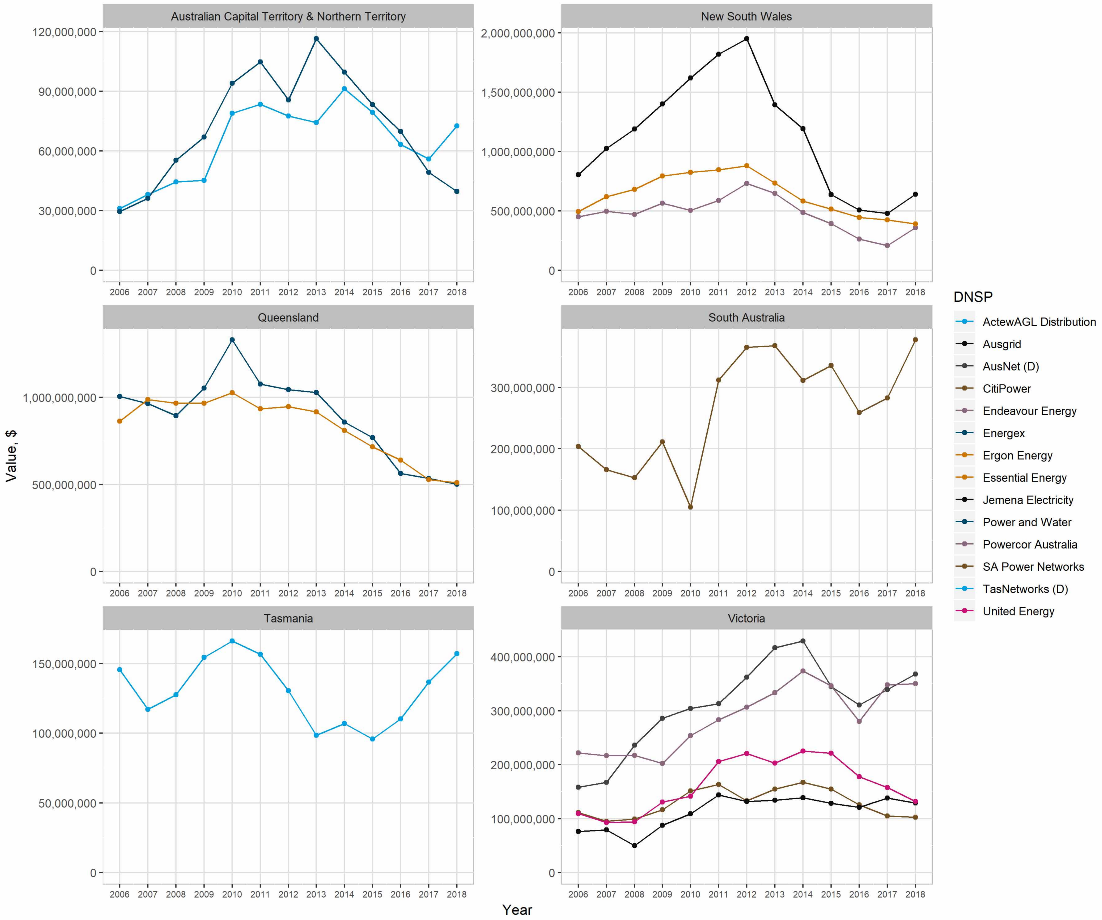


Source: AER.
Note: Values in 2018 real dollar terms.

Figure A.3 shows the combined capex of distribution networks in the NEM. It shows that the combined annual DNSP capex in the NEM rose continually before peaking in 2011-12. Afterwards, the combined annual capex rate rapidly dropped up until 2017-18. There was a small increase in DNSP capex spending during the 2017-18 period. The combined DNSP capex spending during 2016-17 was just over half the rate that was reached at the 2011-12 peak.

Figure A.4 shows the capital expenditure for each DNSP in the NEM. The major decline in distribution-level capex spending across the NEM can be seen in major deceases in capex from Power & Water, Ausgrid, Ergon Energy, Energex and TasNetworks distribution. Many of these decreases started either in 2012-13 or in 2013-14. Ausgrid's decrease was particularly steep. SA Power Networks and the Victorian distribution businesses experienced less steep declining rates.

Figure A.4: DNSP Capex



Source: AER
Note: Values in 2018 real dollar terms.

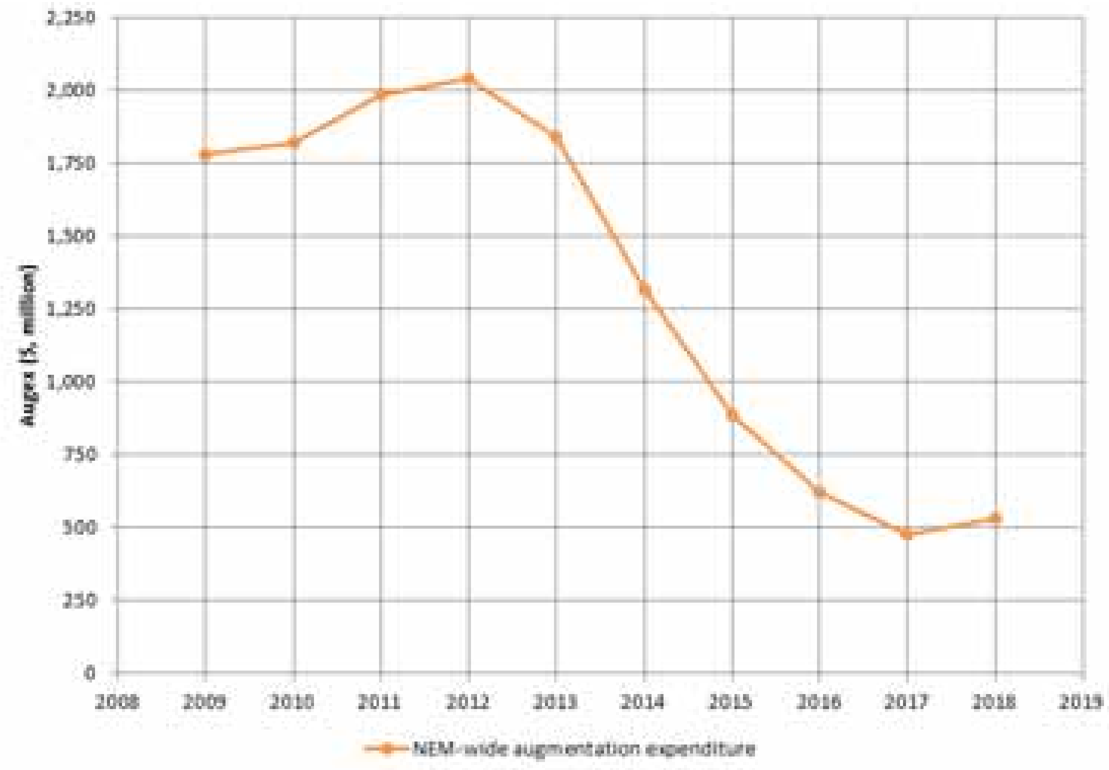
The small increase in combined capex spending at the distribution level during 2017-18 is reflected in a sharp increase in capex spending by SA Power Networks, as well as smaller increases from ActewAGL Distribution, Ausgrid, Endeavour Energy, TasNetworks distribution and AusNet distribution. The remaining distribution businesses showed flat or reduced capex spending during 2017-18.

A major restructure of the NSW network businesses, through the formation of NetworksNSW, took place in 2012. Ausgrid and Endeavour Energy were subequently leased in 2016. Energy Queensland, which contains both Ergon Energy and Energex, was formed in 2016.

A.1.3 DNSP augex trends

Augmentation expenditure (augex) is a major component of capex – it involves the capex needed to increase the capacity of the network to allow for growth in customer demand.[206] Augex spending can also be undertaken in accordance with legislated requirements to allow for load growth.[207] Figure A.5 shows the combined augex expenditure for DNSPs in the NEM.

Figure A.5: **Combined DNSP Augex in the NEM**



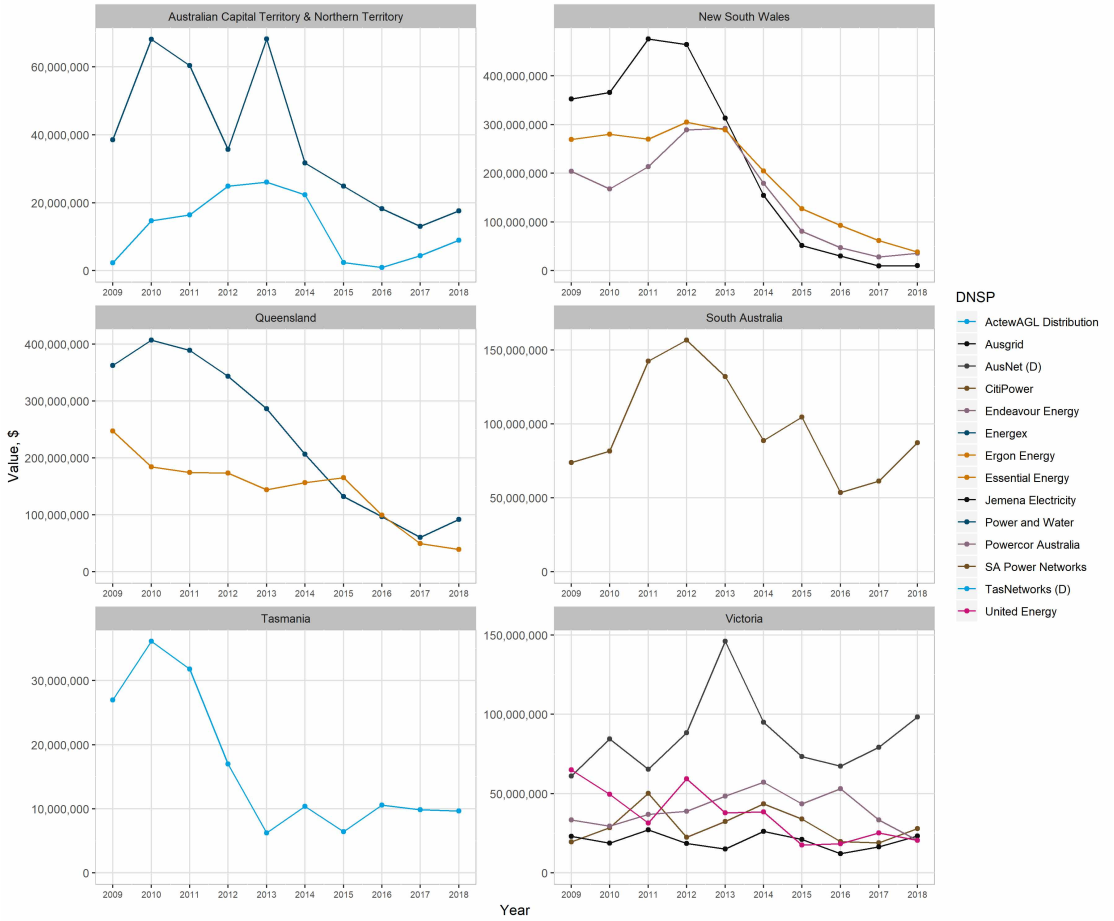
Source: AER
Note: Values in 2018 real dollar terms.

The DNSP augex trend mirrors the broader distribution-level capex trend. Augex spending peaked at 2011-12 and then declined until 2017-18, followed by a small increase in the past year. Augex spending in 2017-18 was less than a quarter of the level of augex spending reached during 2011-12.

206 AER, *Guidance document: AER Capex model – data requirements*, June 2011, p. 4.

207 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 27.

Figure A.6: DNSP Augex



Source: AER
Note: Values in 2018 real dollar terms.

Figure A.6 shows the augex spending for each DNSP in the NEM. All NEM regions except Victoria showed strong declines in augex since 2011. The Victorian distribution networks, and particularly Ausnet, had variable augex spending during this time.

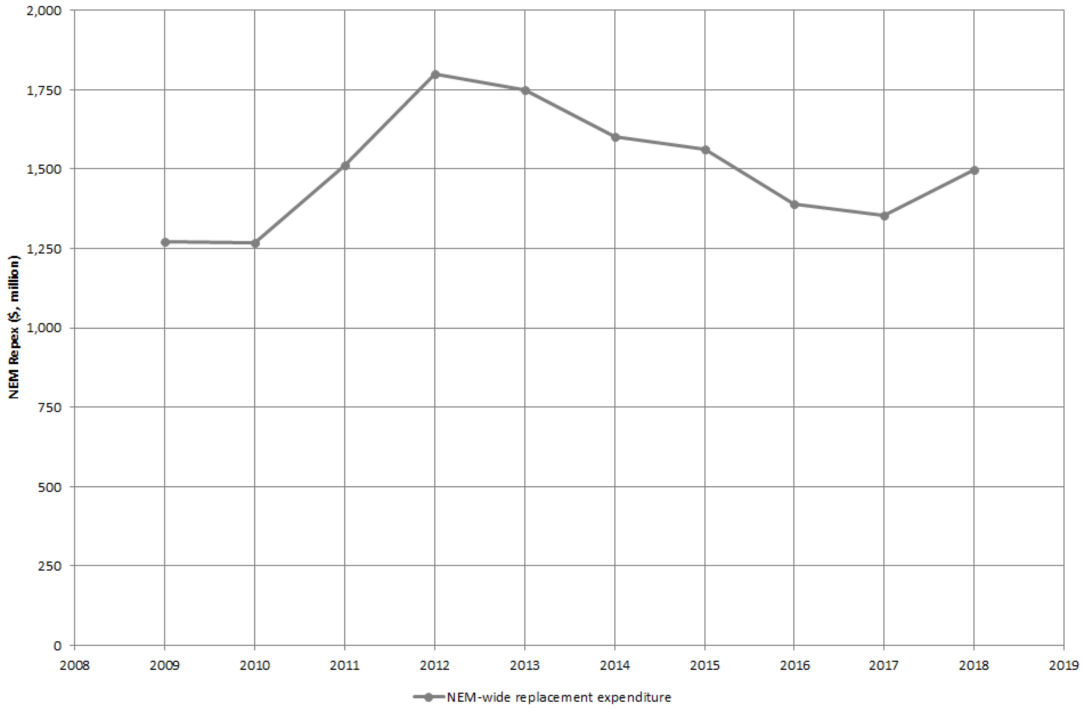
A.1.4 DNSP repex trends

Replacement expenditure (repex) is also a major component of capex – it involves the non-demand driven replacement of an asset at the end of its life.[208] Figure A.7 shows the combined repex expenditure by DNSPs in the NEM. It shows that repex at the distribution level decreased after reaching a peak during 2011-12, although unlike augex, the decrease

208 Note: There is some overlap of augmentation and replacement expenditure. Augmentation expenditure can sometimes involve the replacement of assets at or close to the end of their life.

for repex spending was not a steep one. DNSP repex spending did experience a small increase during the 2017-18 period after reaching a trough in the previous year.

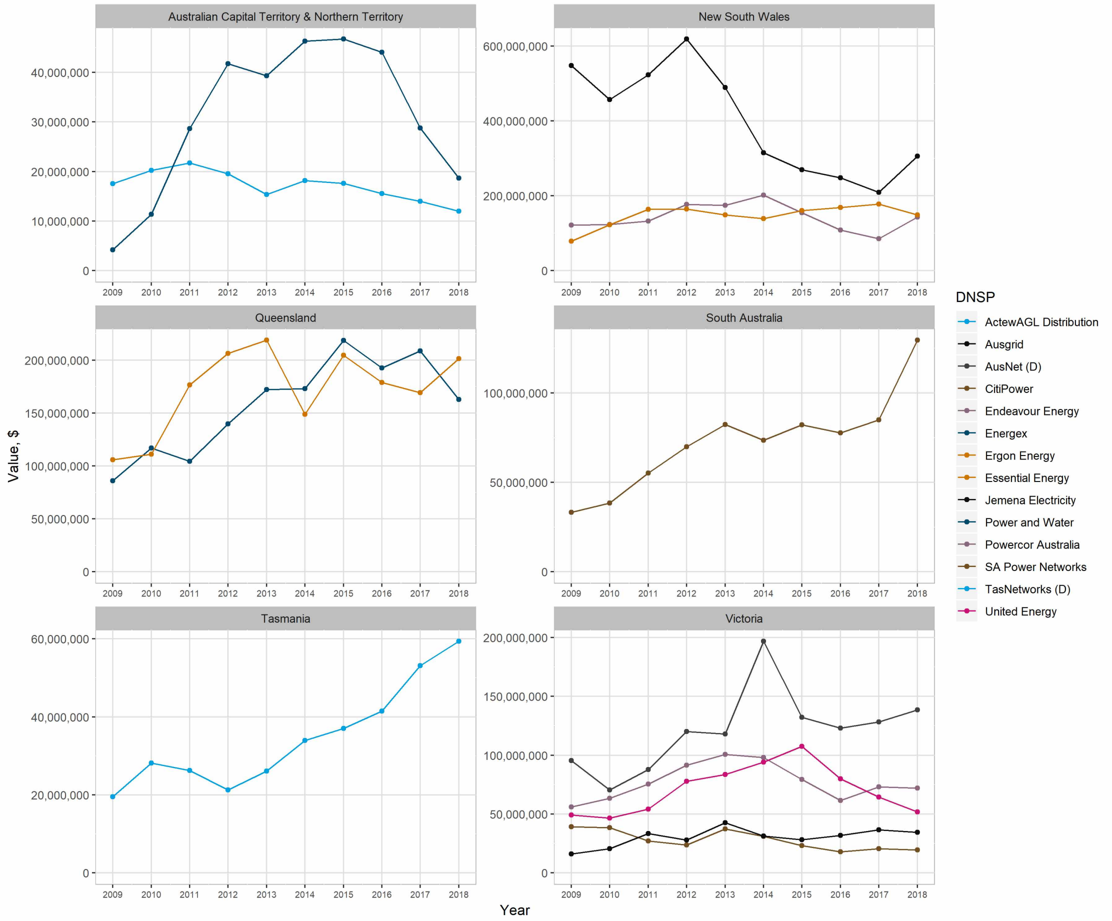
Figure A.7: Combined DNSP Repex in the NEM



Source: AER
Note: Values in 2018 real dollar terms.

Figure A.8 shows repex spending for each DNSP in the NEM.

Figure A.8: DNSP Repex

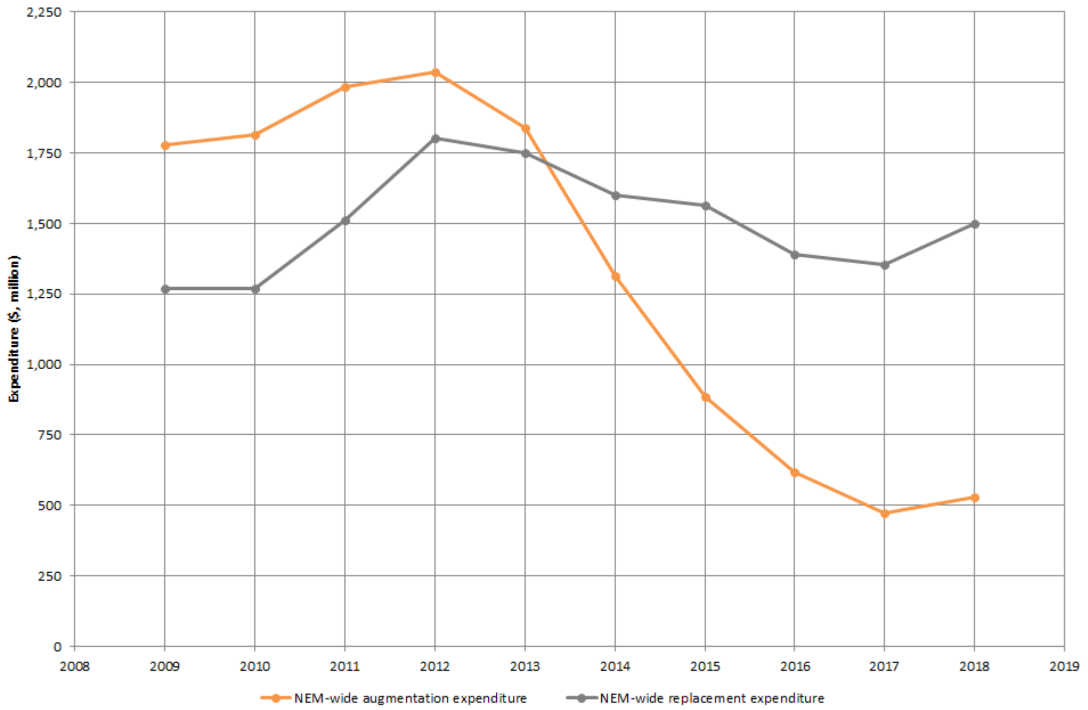


Source: AER
Note: Values in 2018 real dollar terms.

A.1.5 DNSP Repex - Augex comparison

Figure A.9 compares the level of combined distribution augmentation and replacement expenditure across the NEM. It shows that since 2012-13, the level of repex in the NEM has outstripped investment expansion, with the difference reaching nearly a 3:1 ratio during 2017-18.

Figure A.9: NEM DNSP Repex - Augex comparison

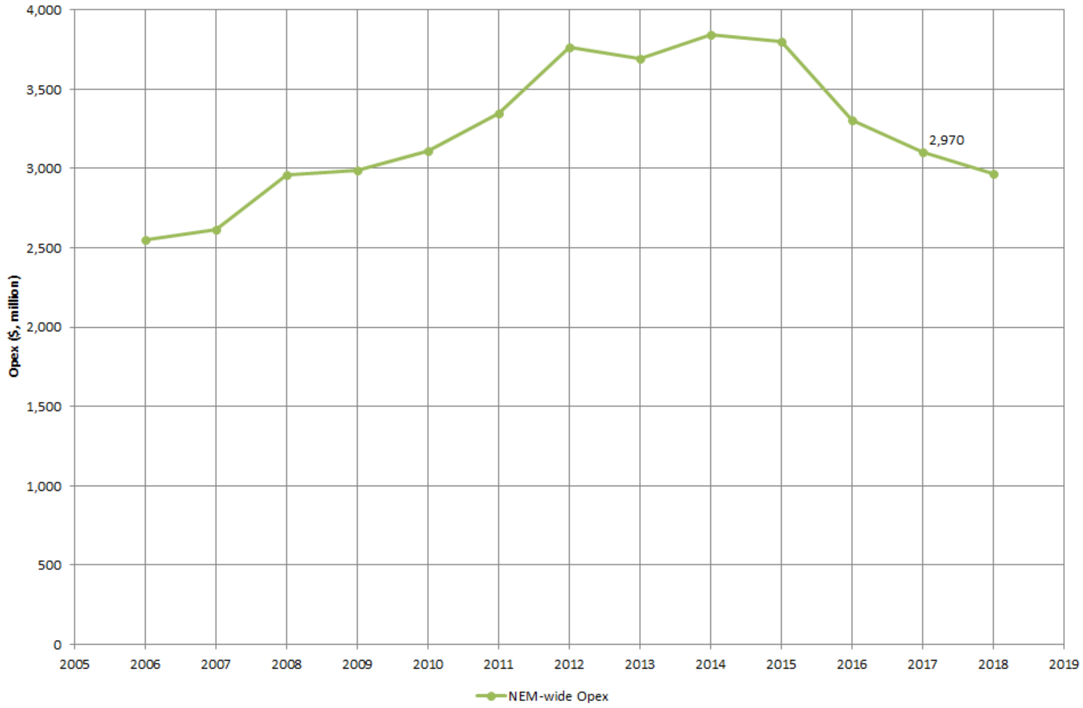


Source: AER
Note: Values in 2018 real dollar terms.

A.1.6 DNSP Opex trends

Operational expenditure (opex) refers to the operational, maintenance and other non-capital expenses that are incurred in the provision of network services. Figure A.10 shows the combined level of distribution operational expenditure across the NEM for the past several years. It shows that DNSP opex across the NEM increased until 2011-12, remained near its peak until 2014-15 and has been declining since then.

Figure A.10: Combined DNSP Opex in the NEM



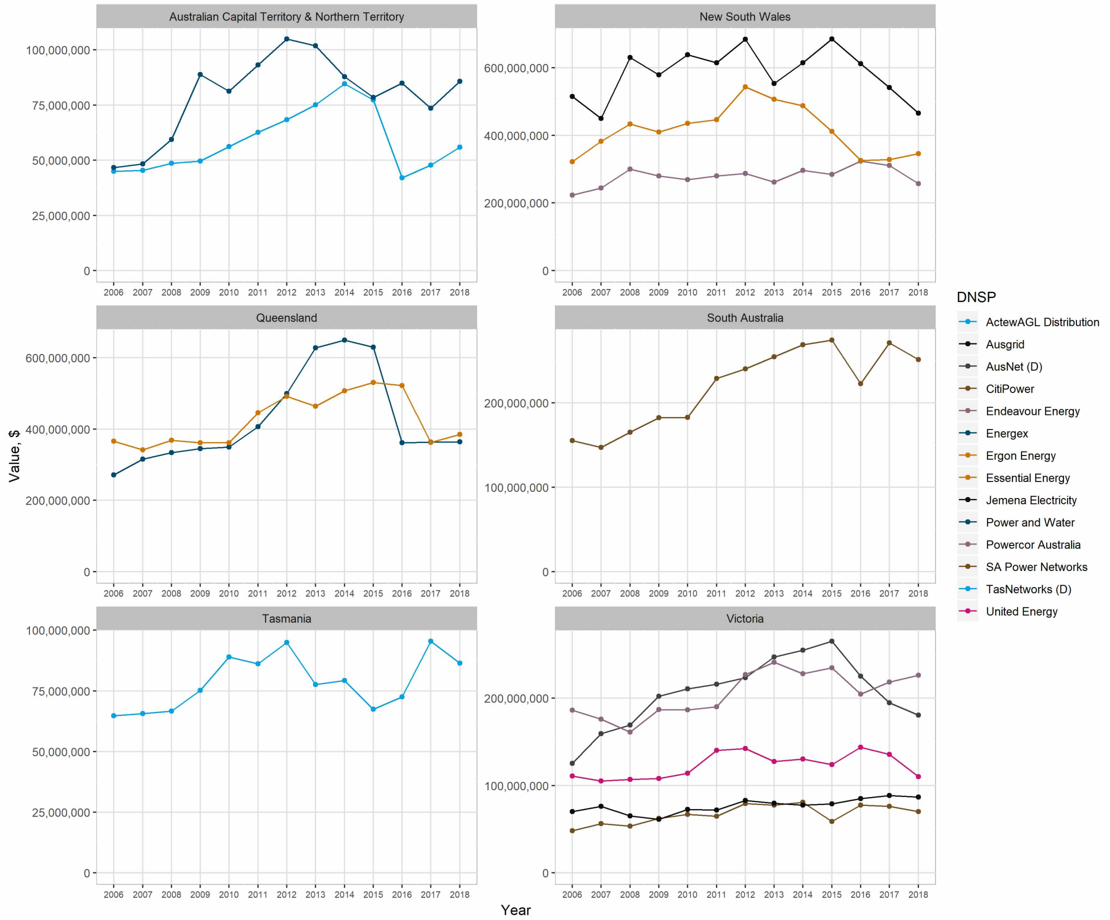
Source: AER
Note: Values in 2018 real dollar terms.

Efficiency benchmarking carried out by the AER since 2014 may have contributed to this reduction, as well as increases to operational expenditure efficiency by many distribution networks in recent years.[209]

Figure A.11 shows the opex expenditure by DNSPs in the NEM. It shows that the reduction in opex spending at the distribution level across the NEM appears to have been underpinned by major opex spending decreases for Ausgrid, AusNet, Essential Energy and Ergon Energy. The opex spending of Endeavour Energy and most of the Victorian distribution businesses has been relatively flat.

209 AER, *Annual Benchmarking Report – Electricity distribution network service providers*, November 2018, p. vi.

Figure A.11: DNSP Opex

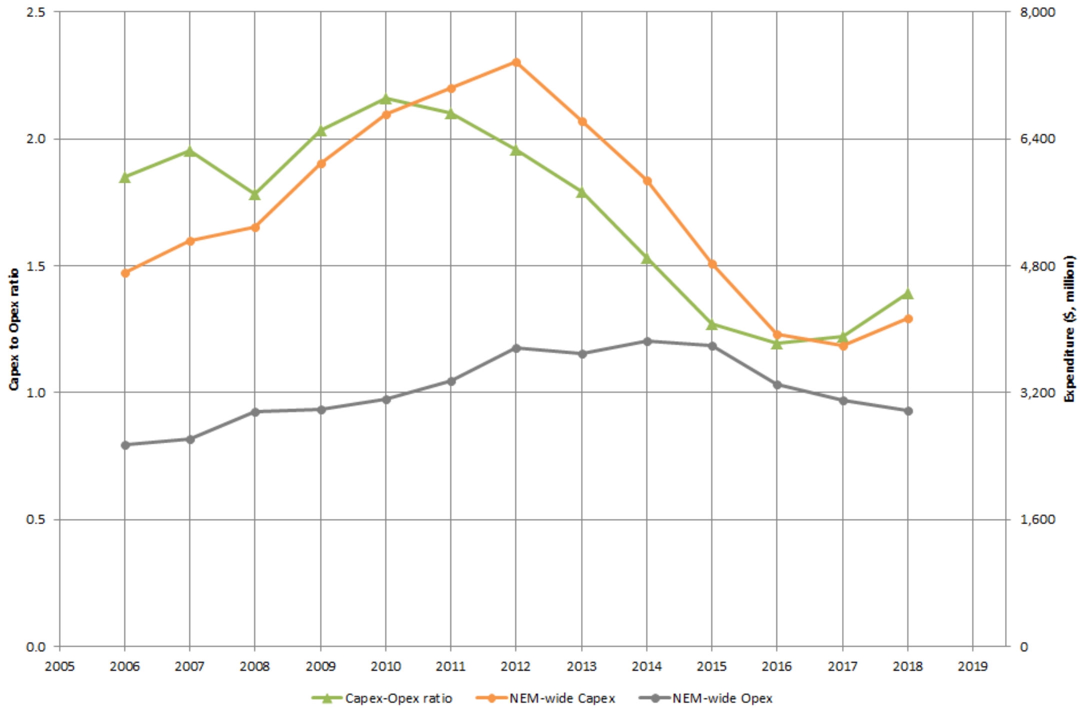


Source: AER
Note: Values in 2018 real dollar terms.

A.1.7 DNSP Capex/Opex rates

Figure A.12 shows the combined NEM capex to opex distribution level spending over the past several years. It shows that the movement of the annual combined NEM capex to opex ratio was mostly dictated by the capex trends, as DNSP opex spending experienced relatively small shifts over recent years compared to capex spending.

Figure A.12: DNSP Capex/Opex ratio



Source: AER
Note: Values in 2018 real dollar terms.

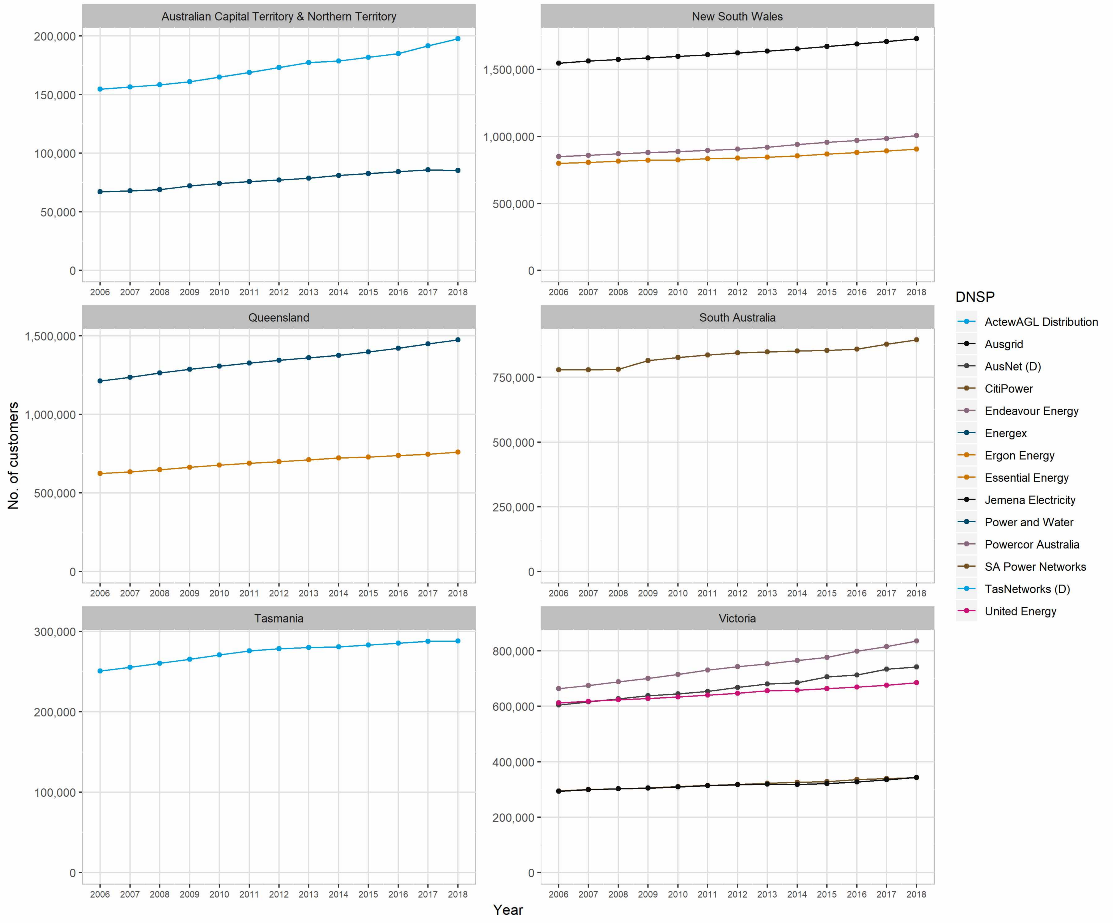
The ratio has begun to rise again in line with recent capex spending increases and opex spending decreases.

A.2 Other trends for DNSPs

A.2.1 DNSP customer numbers

Figure A.13 shows customer numbers for all the DNSPs in the NEM over recent years. It shows small but steady increases in customer numbers for most of the DNSPs.

Figure A.13: DNSP customer numbers

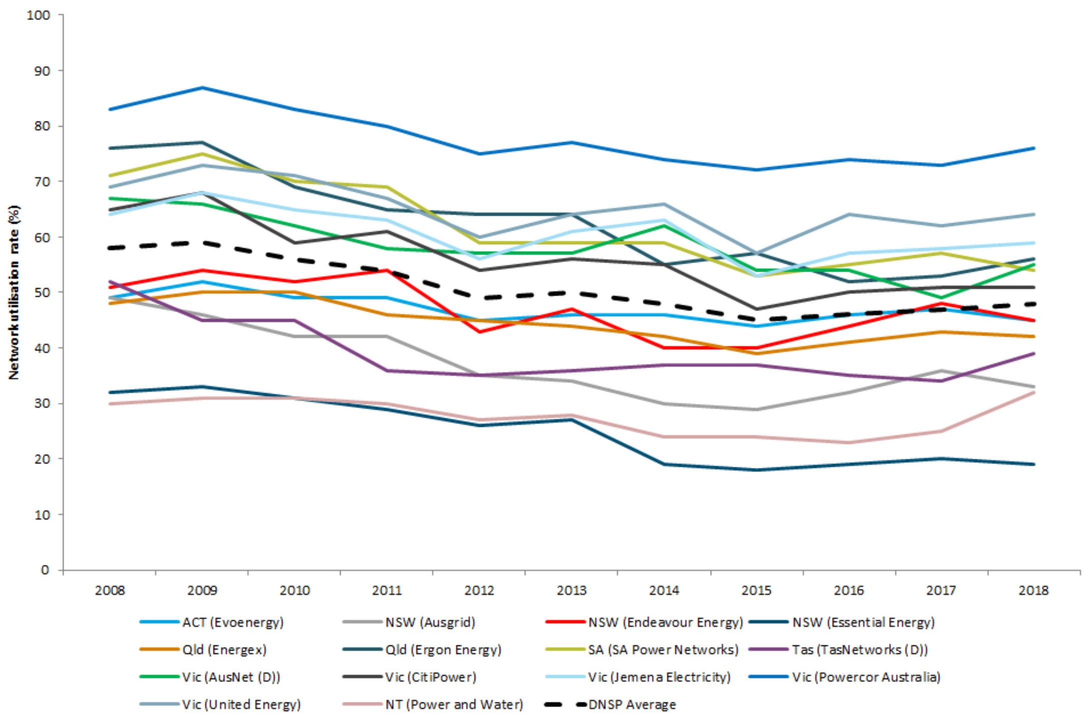


Source: AER

A.2.2 DNSP Utilisation

Figure A.14 shows the utilisation rates for DNSPs in the NEM, as well as the average rate of all the DNSPs. These rates indicate the extent to which a distribution network's assets are being used to meet maximum demand.

Figure A.14: DNSP Utilisation



Source: AER, Annual Benchmarking Reports 2018; RINs submitted by network businesses.
Note: This chart uses non-coincident summated raw system annual peak demand divided by total zone substation transformer capacity.

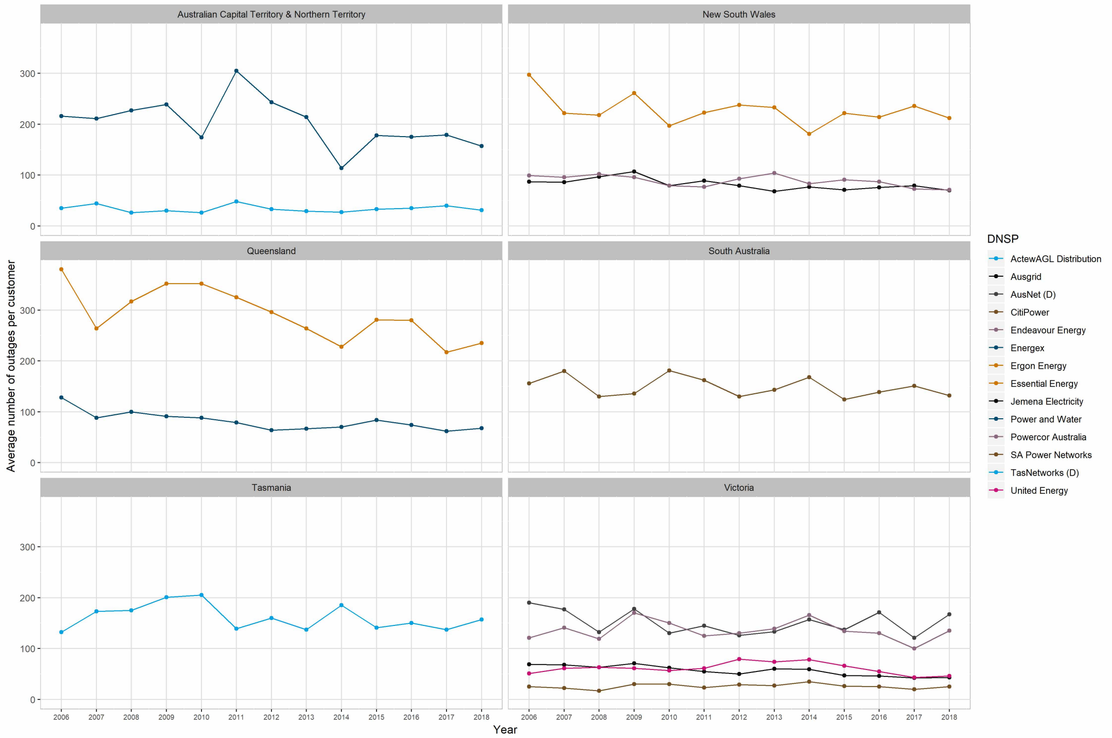
A.2.3 DNSP Reliability

Figure A.15 shows the reliability for DNSPs using the System Average Interruption Duration Index (SAIDI), which indicates the average number of minutes of outages that each customer served by the DNSP experienced, excluding certain events that are not within the control of the distribution network.[210] DNSPs that largely serve urban customers such as Ausgrid, Energex and CitiPower have experienced SAIDI outage rates of around 100 minutes or less. DNSPs such as Essential Energy, Power & Water and Ergon Energy which have larger proportions of rural customers have experienced the highest SAIDI outage rates.

Distribution networks that have predominately rural customers also had outage rates with the highest variability, possibly reflecting the vulnerability of their mostly overhead networks to weather events, while DNSPs with urban customers tended to have flatter outage rates.

210 For a more detailed list of exclusions, see AER, *Distribution Reliability Measures Guideline,* November 2018, p. 8.

Figure A.15: DNSP SAIDI

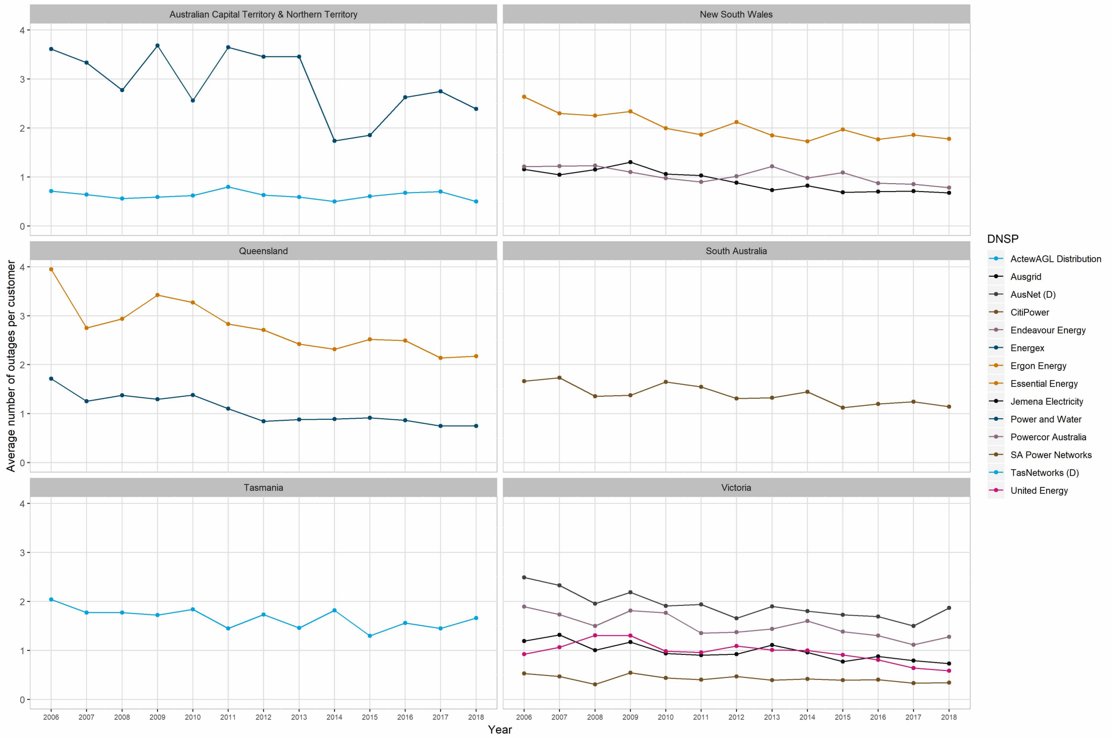


Source: AER

Figure A.16 shows the System Average Interruption Frequency Index (SAIFI), which indicates the average number of outages for each customer served by the DNSP.[211]

211 For a more detailed list of exclusions, see AER, *Distribution Reliability Measures Guideline,* November 2018, p. 8.

Figure A.16: DNSP SAIFI

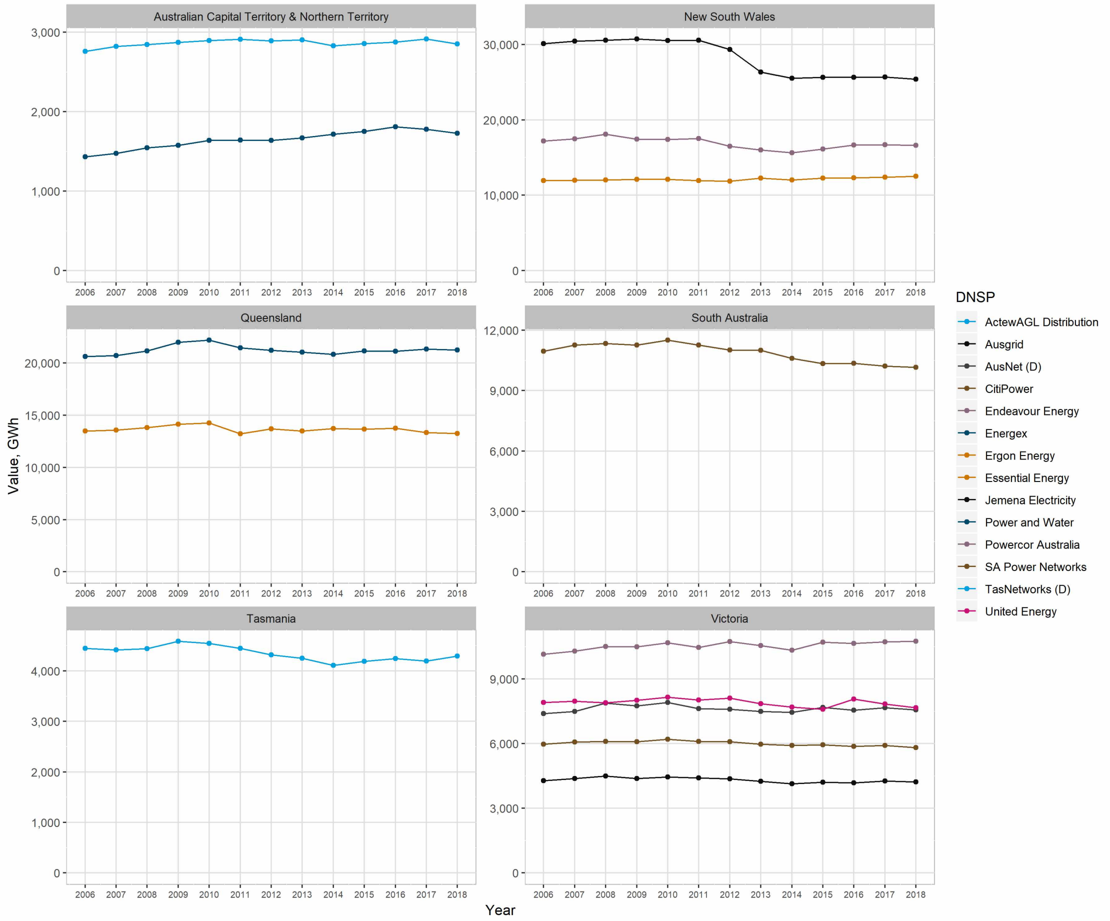


Source: AER

A.2.4 Electricity delivered by DNSPs

Figure A.17 shows the electrical energy delivered to consumers by each DNSP within the NEM. Most of the distribution networks are delivering similar or less energy than they were 10 years ago. Ausgrid experienced a major drop in the energy it delivered to customers between 2010-11 and 2014-15, while SA Power Networks experienced a gradual decrease in the amount of electricity it has delivered to consumers since 2010-11. TasNetworks distribution showed a gradual decrease in the amount of electricity delivered to customers between 2008-09 and 2014-15, before increasing . Power & Water increased gradually and then peaked in 2015-16, before trending downwards. The other DNSPs showed relatively flat amounts of delivered electricity over time.

Figure A.17: Electricity delivered by DNSPs



Source: AER

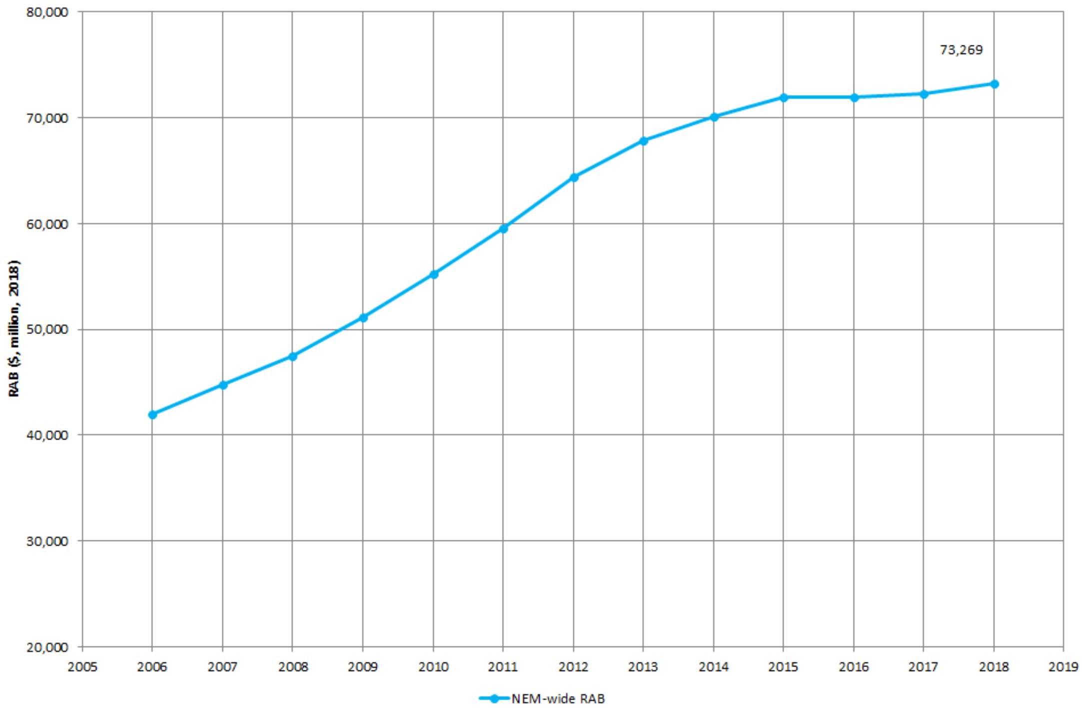
A.3 Investment trends for TNSPs

This section discusses some of the key market metrics for TNSPs. The discussion is limited to the key investment metrics of RABs and capex spending.

A.3.1 TNSP RAB trends

Figure A.18 shows the combined RAB for the TNSPs across the NEM. It indicates that the combined TNSP RABs increased until 2014-15 before flattening off.

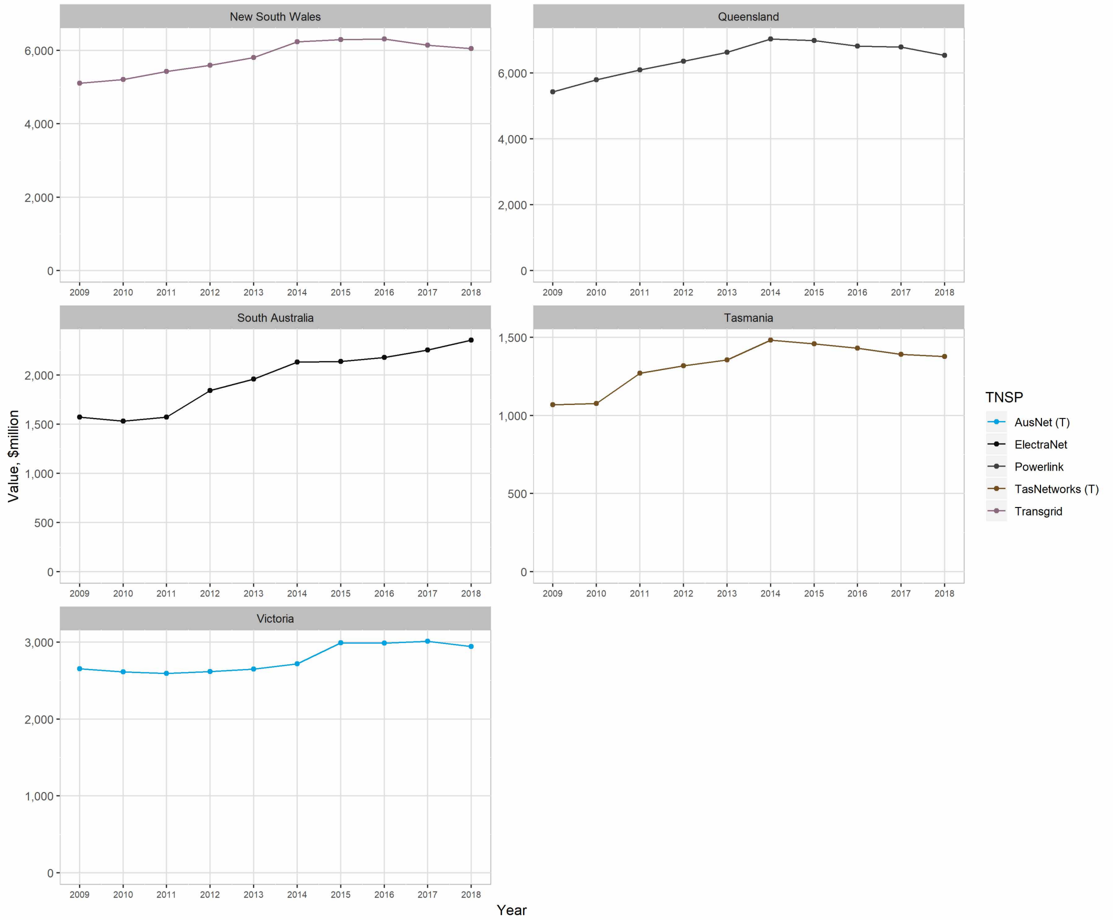
Figure A.18: Combined closing RAB of DNSPs in the NEM



Source: RINs submitted by transmission network businesses.
Note: Values in 2018 real dollar terms.

Figure A.19 shows the RABs for each transmission network service provider. It shows that Powerlink and TasNetworks transmission most closely match the broader combined NEM transmission trend of increasing until 2014-15 and then slowly declining afterwards. TransGrid shows a broadly similar trend. AusNet transmission RAB has been relatively flat, other than one relatively large increase between 2013-14 and 2014-15. SA Power Networks RAB has continued to increase.

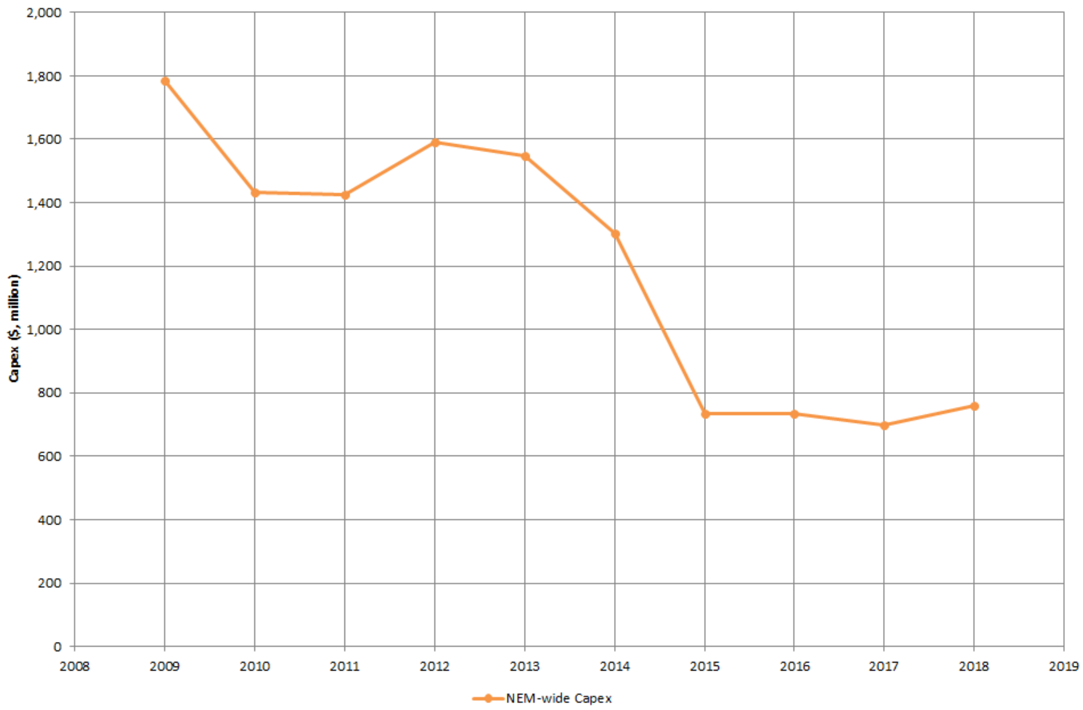
Figure A.19: TNSP RAB



Source: RINs submitted to the AER by transmission network businesses.
Note: Values in 2018 real dollar terms.

A.3.2 TNSP Capex trends

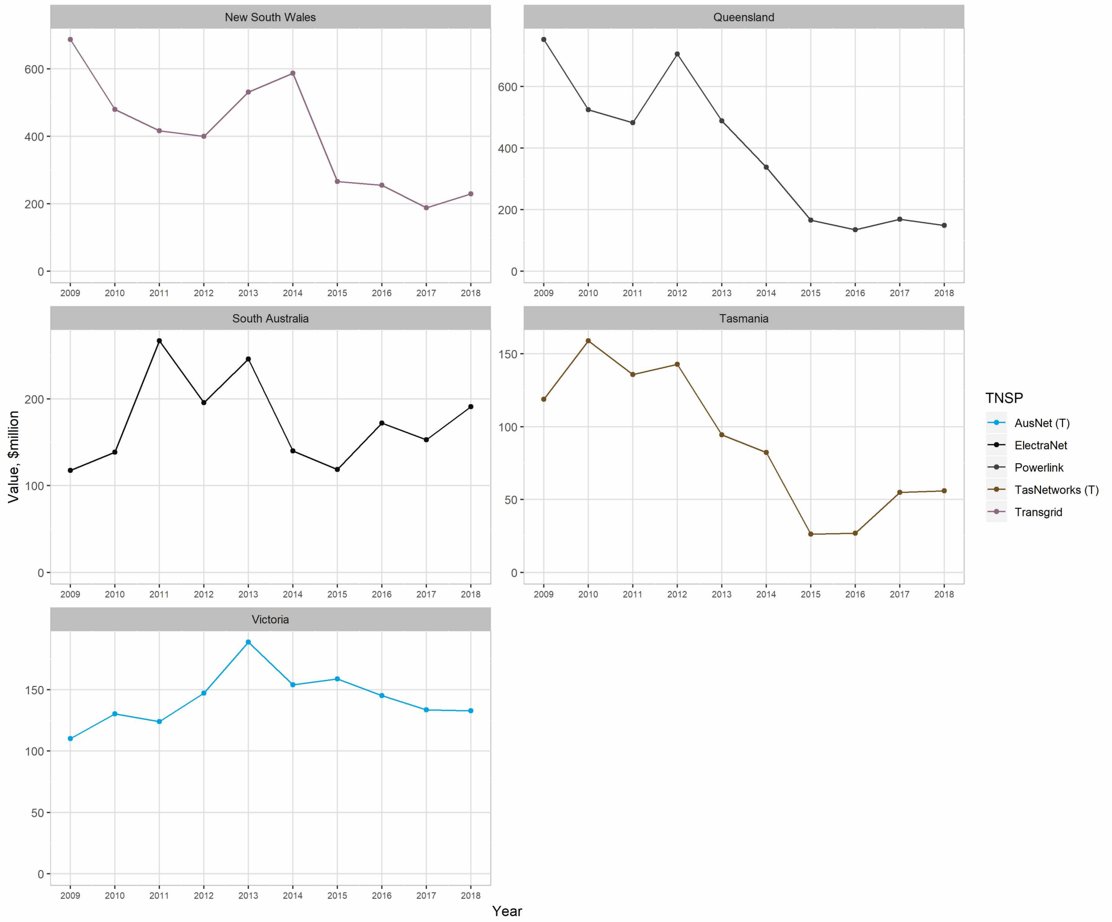
Figure A.20: Combined TNSP Capex in the NEM



Source: RINs submitted to the AER by transmission network businesses.
Note: Values in 2018 real dollar terms.

Figure A.20 shows the combined annual TNSP capex across the NEM. It shows that 2007-08 was a recent peak for transmission capex in the NEM. The NEM transmission capex spending trend was volatile after that peak, prior to a major drop in expenditure between 2012-13 and 2014-15. The combined transmission capex expenditure has been relatively flat since that time.

Figure A.21: TNSP Capex



Source: RINs submitted to the AER by transmission network businesses.
Note: Values in 2018 real dollar terms.

Figure A.21 shows the capex spending for each TNSP in the NEM. They indicate that TransGrid and Powerlink experienced largely similar capex trends to the broader NEM trend.

TransGrid's capex spending increased a little during 2017-18, while Powerlink's capex spending remained flat. TasNetworks transmission's capex spending trend was similar to those of TransGrid and Powerlink.

AusNet transmission and ElectraNet have exhibited a profile that is different to the average expenditure trend. AusNet transmission's capital expenditure increased until it peaked in 2012-13, then its capex spending experienced a gradual decline. ElectraNet's capex trend generally diverged from that of the other TNSPs and has been relatively volatile during most of this period. ElectraNet also exhibited a relatively large increase in capex during 2017-18, when the other TNSPs either experienced flat or slightly increased capex spending.

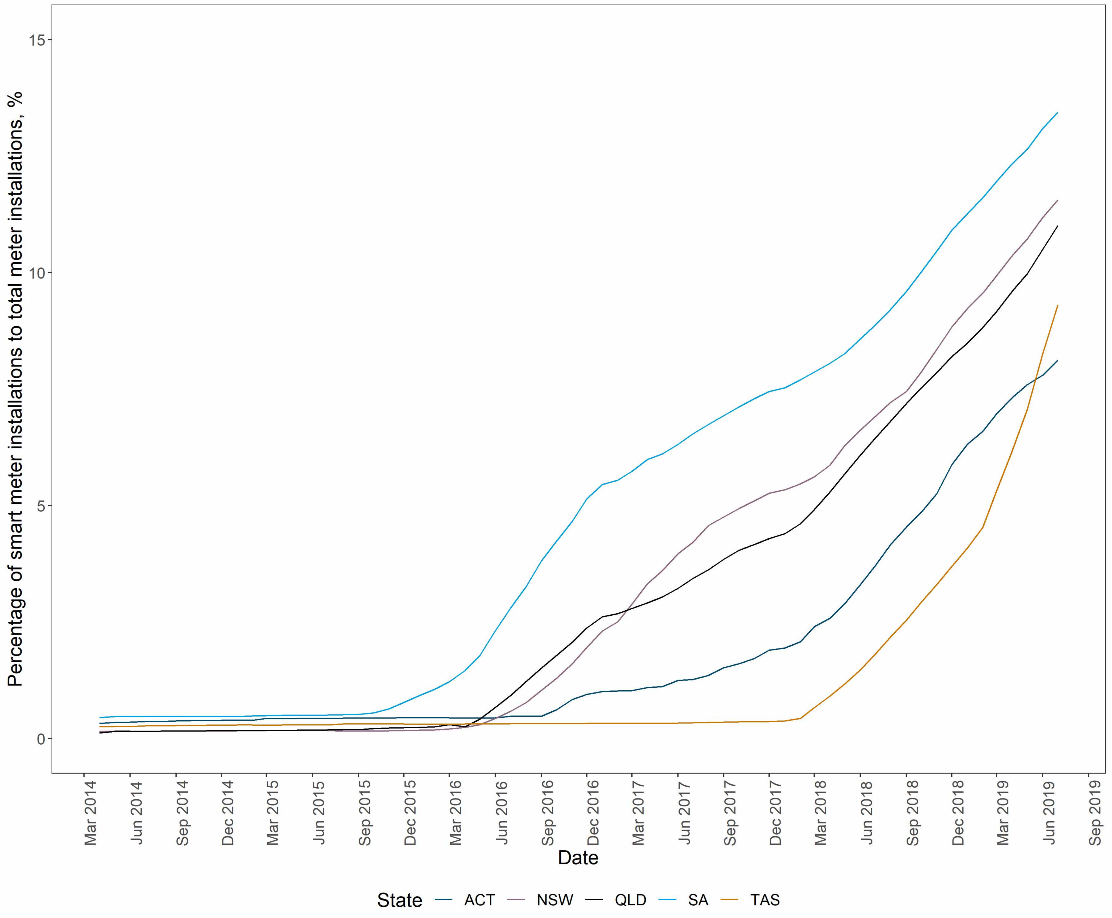
A.4 Other key trends

A.4.1 Small customer smart meter installations

As discussed in Chapter 4, smart meters (also known as interval or advanced meters) are a tool that can help consumers and distribution networks to obtain a better understanding of DER usage and associated distribution network availability.

A competitive smart electricity meter rollout is currently occurring across the Australian Capital Territory, New South Wales, Queensland, South Australia and Tasmania in the wake of the AEMC's *Competition in metering* reforms. Since December 2017, all new and replacement electricity meters need to be smart meters, while retailers are now responsible for managing smart meter installation and maintenance.

Figure A.22: Smart meter installation trends in the NEM



Source: AEMO MSATS data
Note: This chart excludes Victoria. Western Australia and the Northern Territory.

Figure A.22 shows the percentage of small customers that have installed smart meters over the past six years. The chart shows nearly 15% of South Australia's small consumers have installed smart meters. More than 10% of New South Wales and Queensland small customers have also installed smart meters.

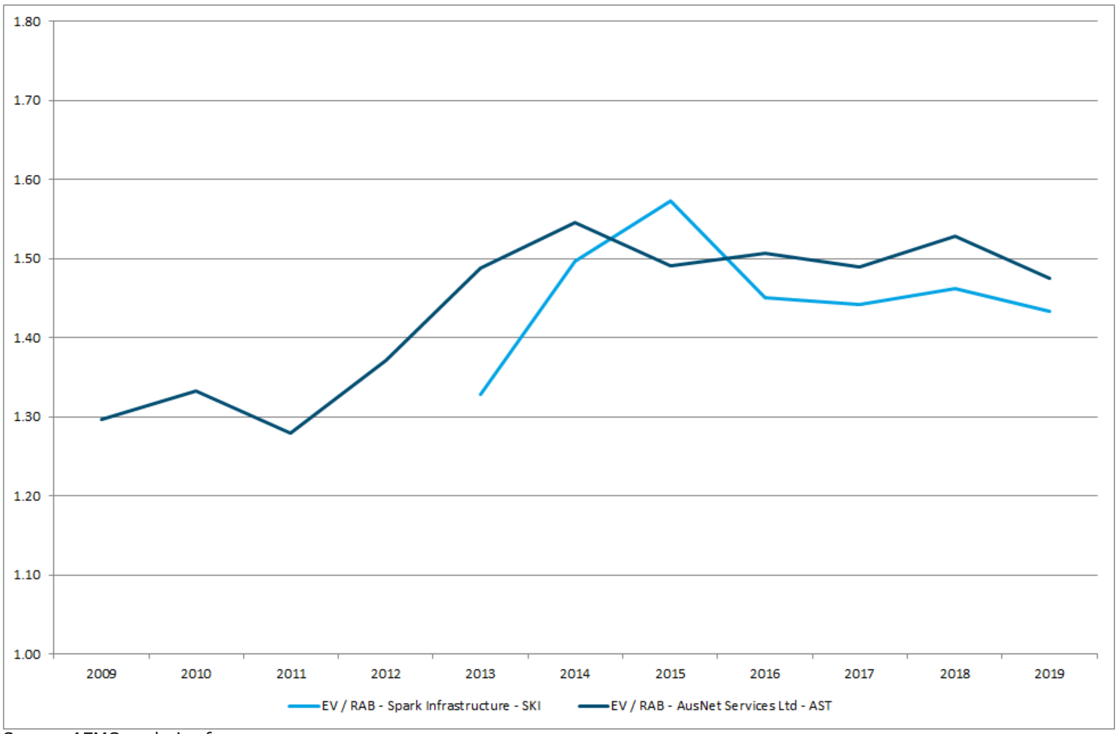
The AEMC is monitoring this rollout of smart meters and are developing an approach paper for industry to detail the data we need to collect from retailers and network service providers and ensure that we understand the challenges and opportunities linked to the spread of smart meters throughout the NEM.

A.4.2 Investment environment

Figure A.23 shows the implied RAB multiples of AusNet Services and Spark Infrastructure, which owns a large stake in SA Power Networks, TransGrid and CitiPower & Powercor, based on the value of their share price and debt levels.[212]

212 A significant proportion of Spark Infrastructure's asset base is regulated assets. For more information, see Spark Infrastructure, *Delivering Future Energy – Annual General Meeting*, May 2019, p. 6 and p. 11.

Figure A.23: RAB multiples for Spark Infrastructure and AusNet Services



Source: AEMC analysis of:

o Spark Infrastructure's annual reports and presentations - https://www.sparkinfrastructure.com/investor-centre/reports-and-presentations?field_year_value=2019

o AusNet Services' company results - https://ausnetservices.com.au/en/Misc-Pages/Links/Investor-Centre/Company-results

o AusNet Services' company valuation by Morningstar - https://www.morningstar.com/stocks/xasx/ast/valuation

o Regulated asset base for:

- SA Power Networks – AER – https://www.aer.gov.au/system/files/Final%20decision-%20SA%20distribution%20determination%202010-11%20to%202014-15.pdf and FINAL DECISION SA Power Networks determination 2015–16 to 2019–20 Attachment 2 – Regulatory asset base

- CitiPower – AER – Victorian electricity distribution network service providers Distribution determination 2011–2015 and FINAL DECISION CitiPower distribution determination 2016 to 2020 Attachment 2 – Regulatory asset base

- PowerCor – AER – FINAL DECISION Powercor distribution determination 2016 to 2020 Attachment 2 – Regulatory asset base

- Transgrid – AER – https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Ausgrid%20distribution%20determination%202019-24%20-%20Attachment%202%20-%20Regulatory%20asset%20base%20-%20April%202019.pdf

- Spark Infrastructure Group – SKI – https://www.sparkinfrastructure.com/investor-centre/reports-and-presentations

- AusNet Services' electricity distribution – AER – FINAL DECISION AusNet Services distribution determination 2016 to 2020 Attachment 2 – Regulatory asset base and https://www.aer.gov.au/system/files/Victorian%20distribution%20determination%20final%20decision%202011-2015%20%2829%20October%202010%29_2.pdf

- AusNet Services' electricity transmission – AER – FINAL DECISION AusNet Services transmission determination 2017-2022 Attachment 2 – Regulatory asset base and https://www.aer.gov.au/system/files/AER%20final%20decision%20for%20SP%20AusNet%27s%202014-17%20regulatory%20control%20period%20-%2031%20January%202014.pdf

- AusNet Services' gas distribution – AER – https://www.aer.gov.au/system/files/AER%20-%20Attachment%202%20-%20Capital%20base%20-%20November%202017_5.pdf and Access arrangement final decision SPI Networks (Gas) Pty Ltd 2013–17 Part 1 March 2013

RAB multiples are the ratio of the market value of a regulated firm to its RAB.[213] A RAB trading multiple that is less than 1 could suggest that the market is applying a discount to investments in regulated assets, making such investments unattractive.[214] While there are contrary arguments,[215] positive trading multiples, particularly of this magnitude, tend to imply the reverse.

213 Darryl Bigger, *Understanding the Role of RAB Multiples in Regulatory Processes*, February 2018, p. 1.

214 NERA Economic Consulting, *RAB growth since the AER's 2013 Rate of Return Guideline*, September 2018, p. iii.

215 For example, Energy Networks Australia, *Submission to the AER Review of the Rate of Return Guideline - Response to Discussion Papers and Concurrent Expert Evidence Sessions*, May 2018, p. 26.

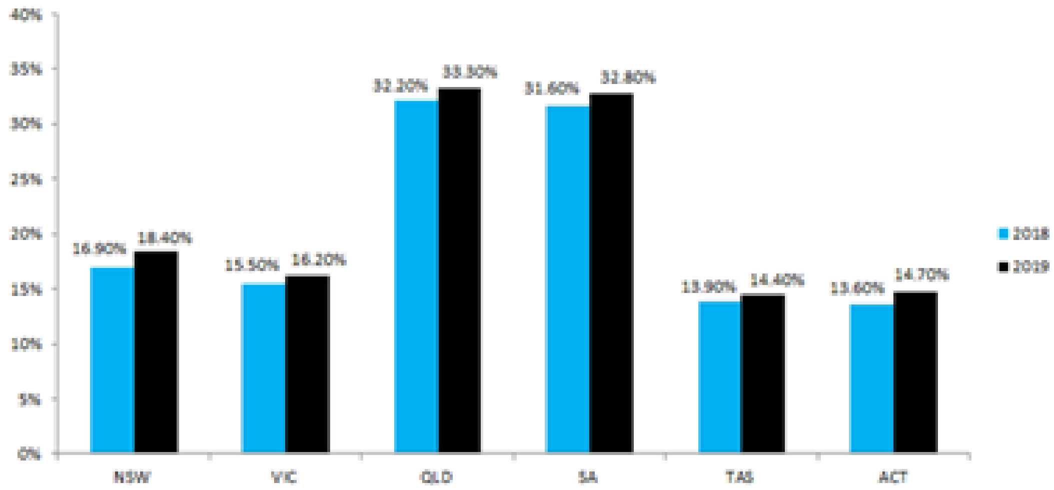
B DER UPTAKE TRENDS

The AEMC monitors DER uptake trends as part of its analysis of the regulatory framework review to inform views on potential improvements to the regulatory framework. This section contains major indicators of the uptake of different types of DER over recent years, as well as forecasts of future DER uptake where available.

B.1 Small customer solar PV trends

Consumers can use install and use solar photovoltaic (PV) generation to power their own appliances or can export the energy it generates into the grid. Many consumers have installed rooftop solar PV over the last few years, forming the first major wave of customer DER uptake. Figure B.1 shows the share of households with solar PV in different areas in the NEM. All of these states and territories have been experiencing strong growth in the share of households with installed solar PV. Approximately 1 in 3 households in South Australia and Queensland have installed solar PV.[216]

Figure B.1: Share of households with solar PV in the NEM

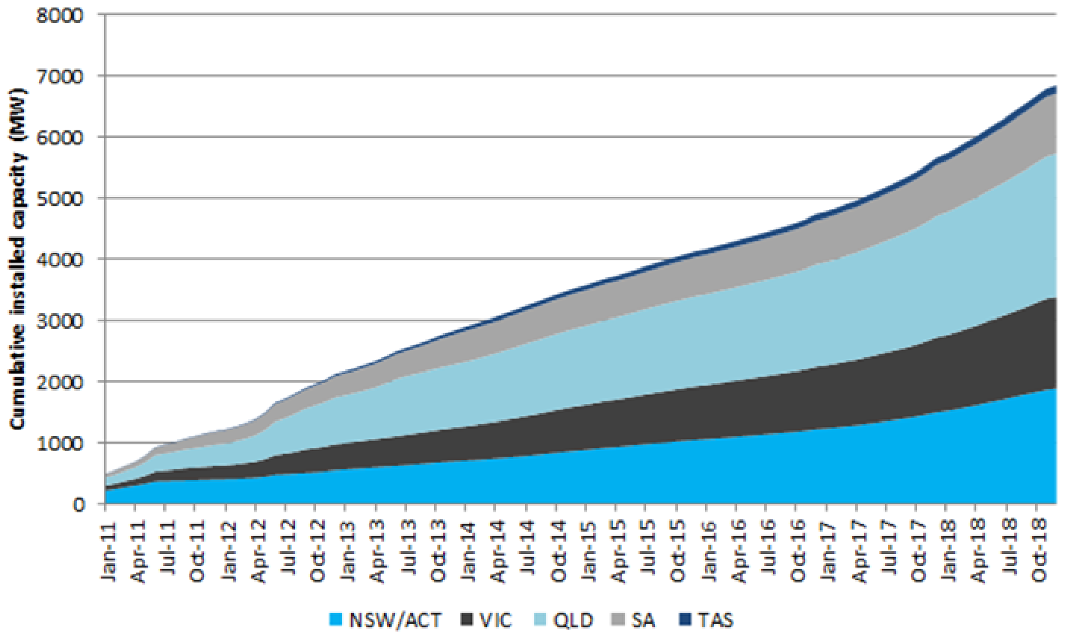


Source: AEMC adaptation of Mapping Australian Photovoltaic installations data from the Australian PV institute
Note: This was calculated by the Australian Photovoltaic Institute by comparing the total number of freestanding and semi-detached dwellings with the number of residential PV systems installed in each area.

As a result, the amount of energy available from residential solar PV has rapidly grown within the national electricity market (NEM)[217] to reach nearly 7000 megawatts (MW) of capacity as of late 2018.[218]

216 AEMC adaptation of Mapping Australian Photovoltaic Installations data from the Australian PV institute
217 Excluding the Northern Territory
218 AEMC adaptation of Mapping Australian Photovoltaic installations data from Australian PV institute. This chart includes solar PV units that are 100 kW or less.

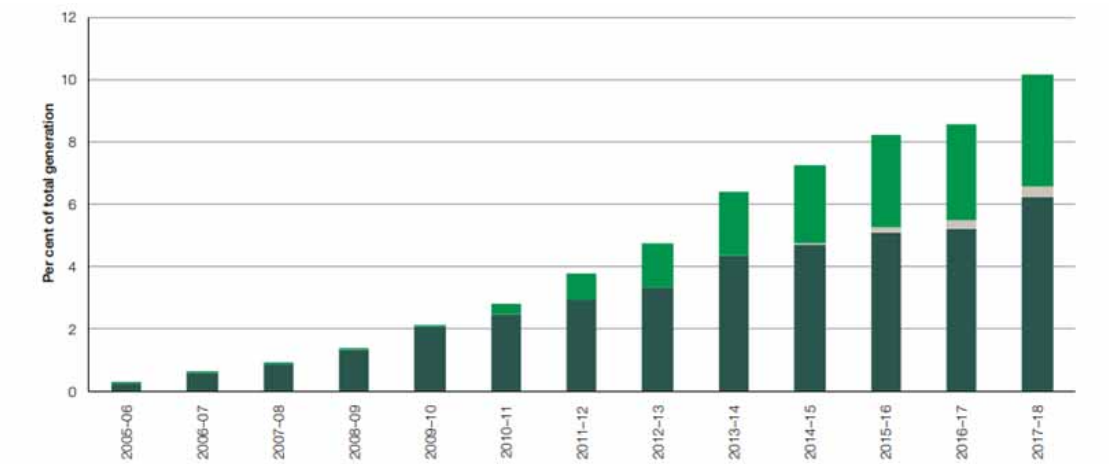
Figure B.2: Installed small-scale solar PV capacity in the NEM regions



Source: AEMC adaptation of postcode data from the Australian PV institute
Note: Only systems below 100 kW were included in the analysis

Solar PV rapidly increased from providing a fractional share of total output in the NEM in 2007-08 to providing around 4% of the total output in 2017-18. This can be seen in Figure B.3.

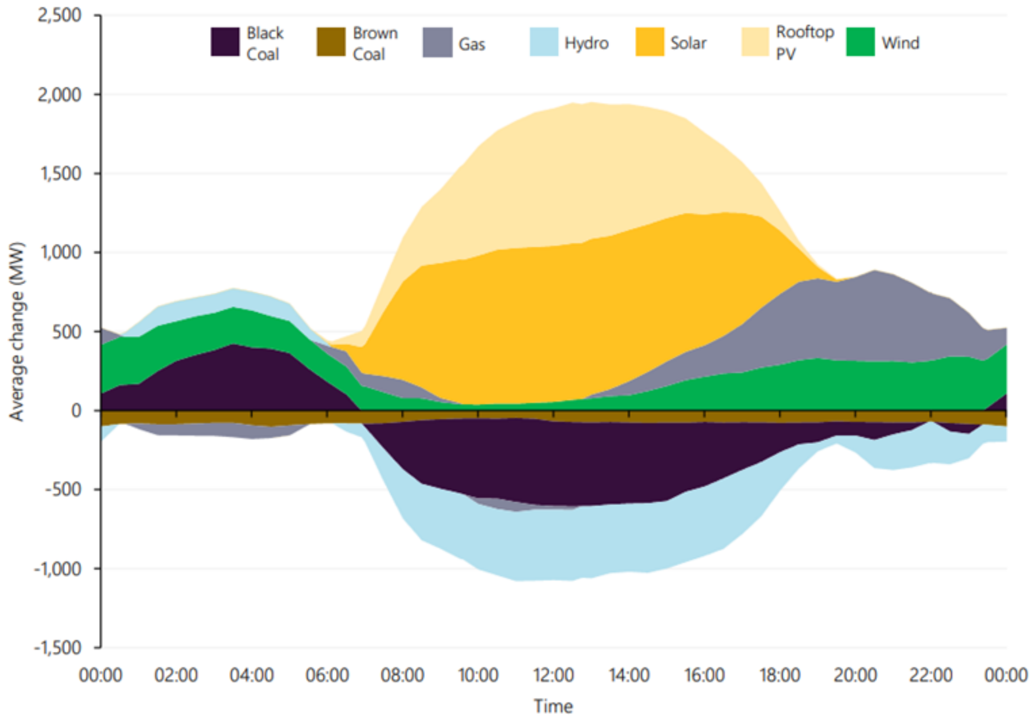
Figure B.3: Wind and solar generation share of total output in the NEM



Source: AER, *State of the Energy Market – 2018*, December 2018, p. 15

This output is particularly notable during the middle of the day, and is becoming more so over time.[219]

Figure B.4: Change in NEM supply sources by time of day



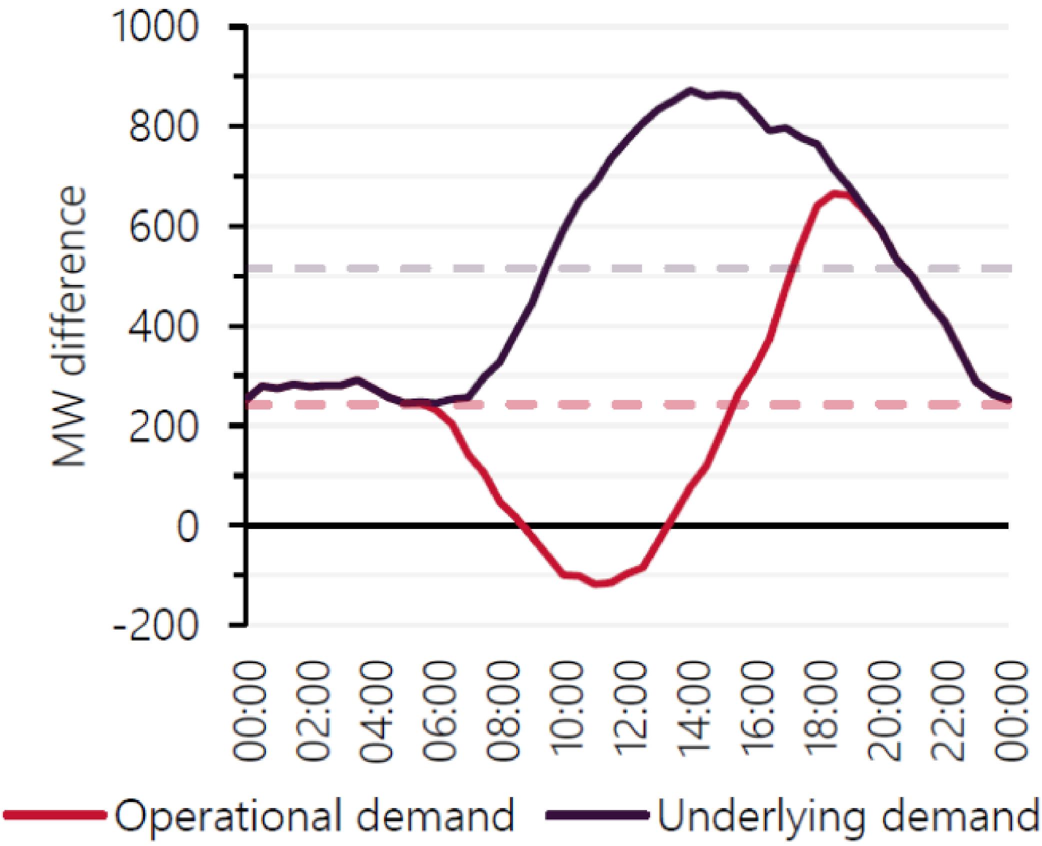
Source: AEMO, *Quarterly Energy Dynamics – Q1 2019*, May 2019, p. 11.
Note: This figure compares Q1 2019 to Q1 2018.

While underlying demand is increasing, the impact of rooftop PV is changing the shape of the demand curve. This can be seen in Figure B.5:[220]

219 AEMO, *Quarterly Energy Dynamics – Q1 2019*, May 2019, p. 11.

220 AEMO, *Quarterly Energy Dynamics – Q1 2019*, May 2019, p. 6. Operational demand refers to the electricity used by residential, commercial, and large industrial consumers, as supplied by scheduled, semi-scheduled, and significant non-scheduled generating units. Underlying demand is consumers' total demand for electricity from all sources, including the grid and distributed resources such as rooftop PV.

Figure B.5: Change in NEM demand by time of day

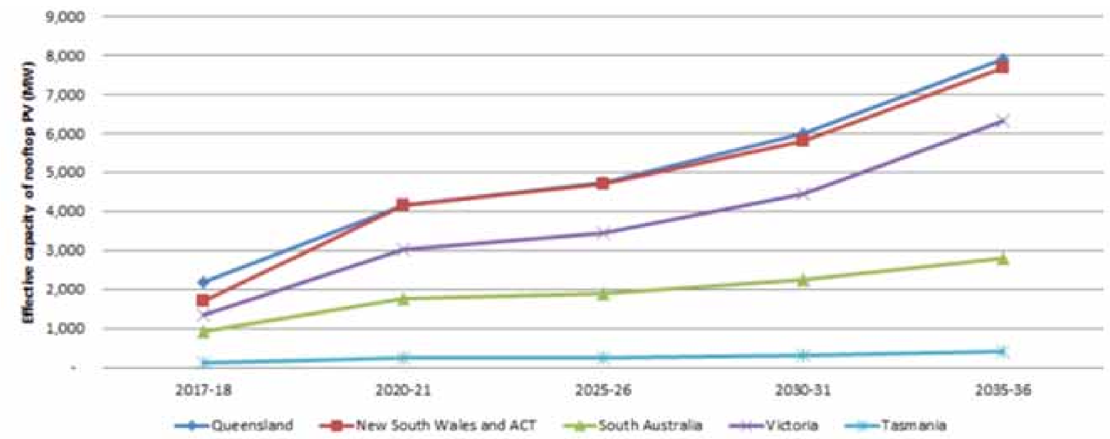


Source: AEMO, *Quarterly Energy Dynamics – Q1 2019*, May 2019, p. 6.
Note: This figure compares Q1 2019 to Q1 2018.

Solar PV uptake is projected to continue to grow rapidly in future years, reaching 8000 MW of total capacity across the NEM[221] by 2035-36.

221 Excluding the Northern Territory.

Figure B.6: Installed residential rooftop PV capacity forecasts

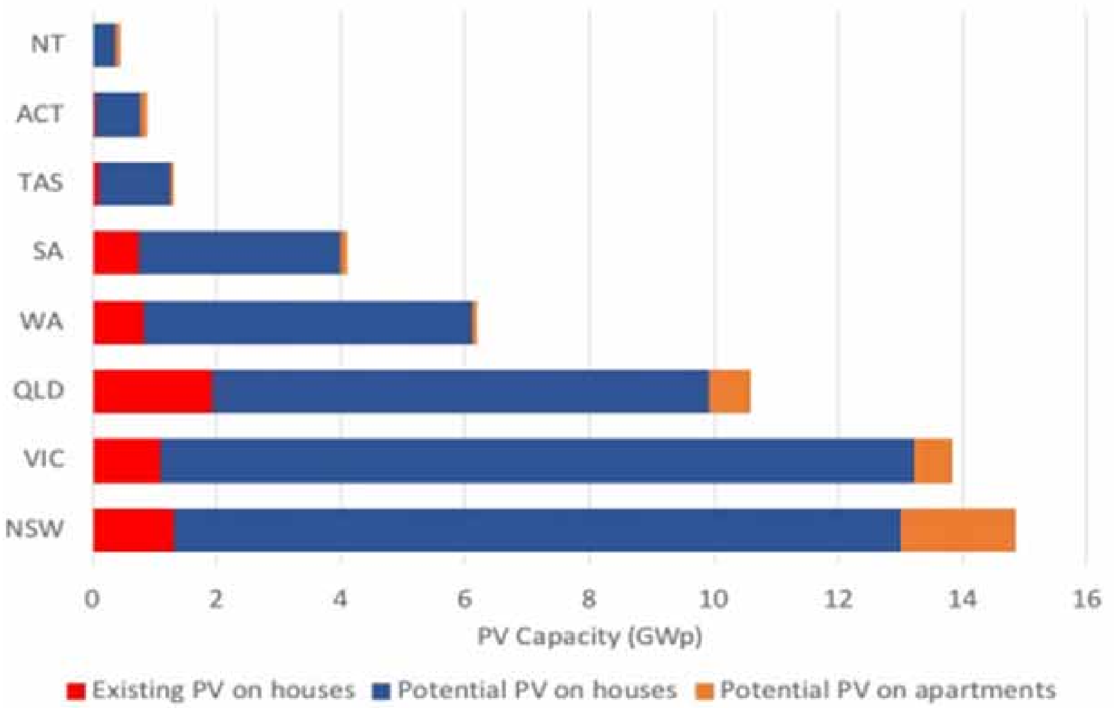


Source: AEMC, *Annual Market Performance Review 2018 - Final Report*, April 2019, p. 48. Initially sourced from AEMO data.

Households across the NEM have been estimated to be able to host a maximum of approximately 48 gigawatts peak (GWp) of solar PV, which suggests that solar PV will become a major supplier of energy in the NEM if consumers continue to adopt the technology in large numbers in the future.[222] The locations where this PV could be installed are shown in Figure B.7.

222 University of NSW / Australian PV Institute, Mike Roberts et al., *Solar Trends Report for Solar Citizens*, December 2018, p. 12.

Figure B.7: Estimated existing and potential solar PV capacity in Australia

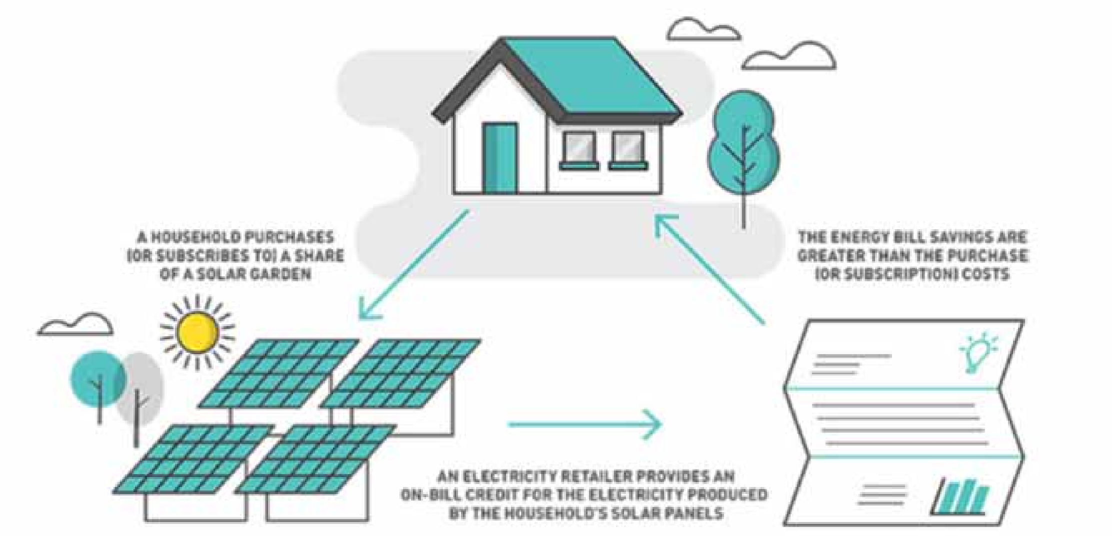


Source: Mike Roberts et al., *Solar Trends Report for Solar Citizens*, University of NSW / Australian PV Institute, December 2018, p. 12.

Community solar is also emerging as a way for consumers to enjoy the benefits of solar PV if they are unable to set up solar panels on their own roof or in addition to that option. According to the Community Power Agency, there are 104 community projects operating across Australia, including solar projects, electric vehicle charging stations or community-owned retailers.[223] An example of a community solar model can be found in Figure B.8.

223 For more details of these projects, see Community Power Agency, 2019, 'Community Energy Map', viewed 28 August 2019, https://cpagency.org.au/resources/map/. Source data on community energy groups was accessed on 28/08/19.

Figure B.8: A possible community solar model



Source: Alison Potter, 28 December 2017, 'Solar for renters and unit dwellers', viewed 28 August 2019, https://www.choice.com.au/home-improvement/energy-saving/solar/articles/community-energy-projects
Note: This model was developed by the Community Power Agency and University of Technology Sydney

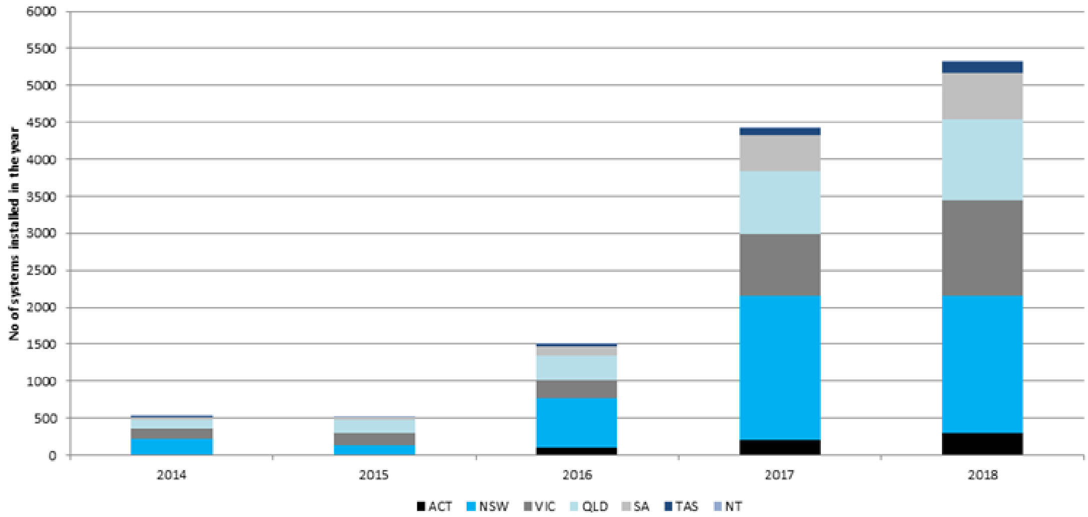
B.2 Small customer battery storage trends

Because batteries can charge and discharge energy generated by solar PV or imported from the grid at different times, battery storage can provide more active control and ways to use electricity. These could include:

- selling stored energy when energy prices are high
- providing network support in exchange for payments or
- using the energy stored by the battery for their own electrical appliances when the sun isn't shining.

While battery storage devices are more expensive than solar PV, their costs are dropping and consumers are adopting them in increasing numbers, as can be seen in Figure B.9.

Figure B.9: Combined battery storage and PV system installations



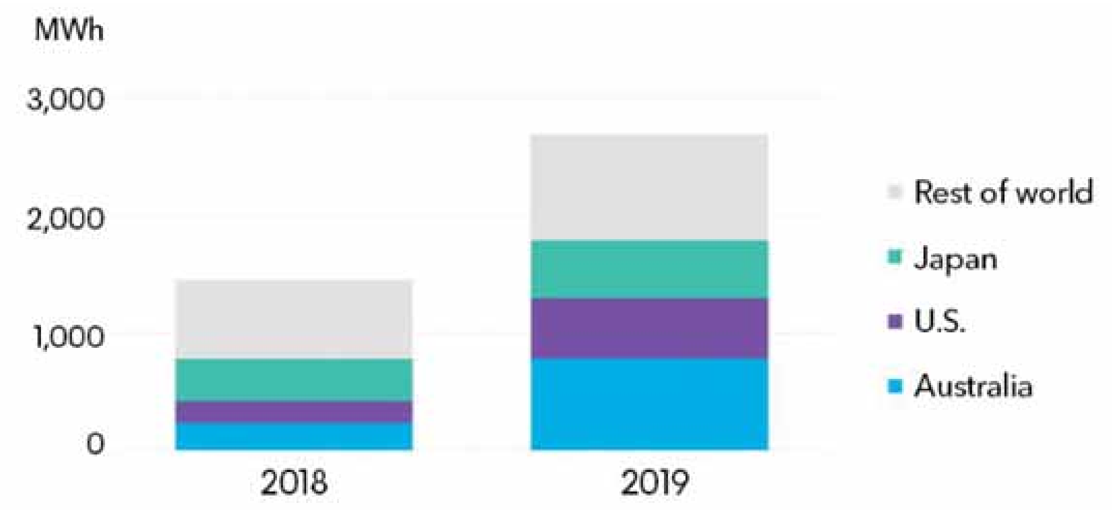
Source: AEMC adoption of data from Clean Energy Regulator - Solar PV systems with concurrent battery storage capacity by year and state/territory. Clean Energy Regulator, 20 August 2019, 'Postcode data for small-scale installations', viewed 8 July 2019, http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations

Note: The Clean Energy Regulator collects some information about battery storage systems that are included in the installation of small-scale generation (solar PV) units. For more details, see Clean Energy Regulator, 5 June 2018, 'Battery storage and the Small-scale Renewable Energy Scheme', viewed 28 August 2019, http://www.cleanenergyregulator.gov.au/RET/How-to-participate-in-the-Renewable-Energy-Target/Choosing-a-system/battery-storage-and-the-small-scale-renewable-energy-scheme

Australia is leading the way with the installation of battery storage, with approximately one quarter of global battery installations by capacity expected to be installed in Australia during 2019.[224]

224 Bloomberg NEF, 22 January 2019, *Australia to be Largest Residential Storage Market in 2019*, viewed 28 August 2019, https://about.bnef.com/blog/australia-largest-residential-storage-market-2019/.

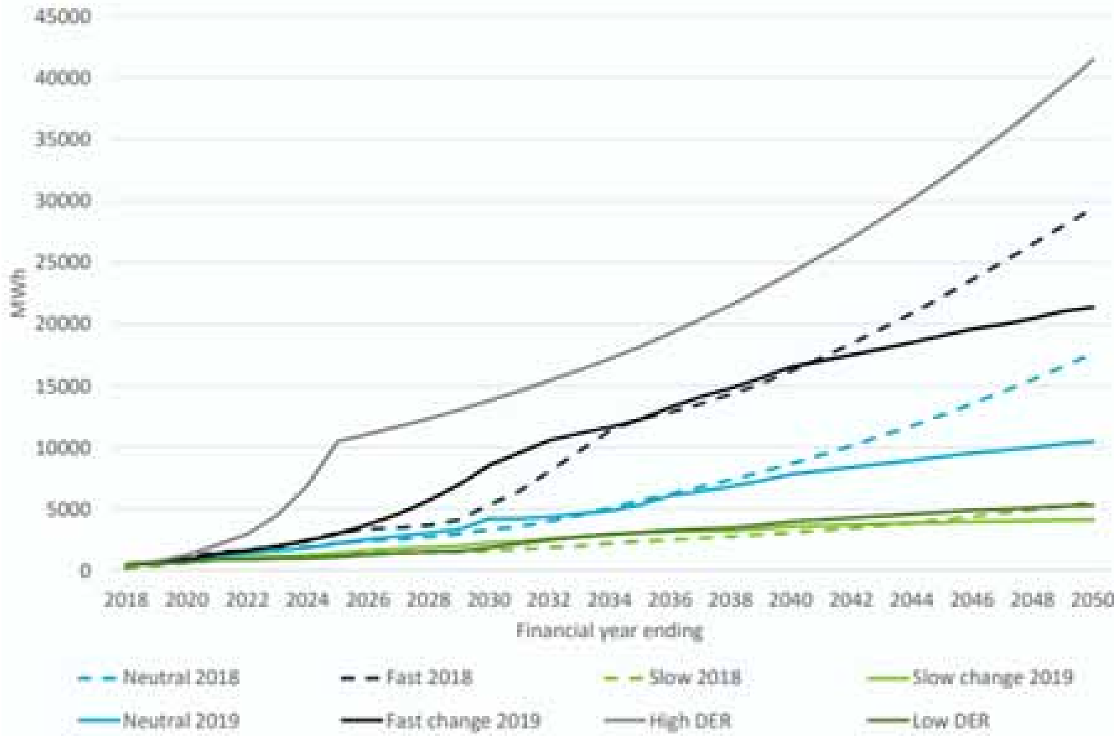
Figure B.10: Estimated and forecast residential storage installations



Source: Bloomberg NEF, 22 January 2019, *Australia to be Largest Residential Storage Market in 2019*, viewed 28 August 2019, https://about.bnef.com/blog/australia-largest-residential-storage-market-2019/

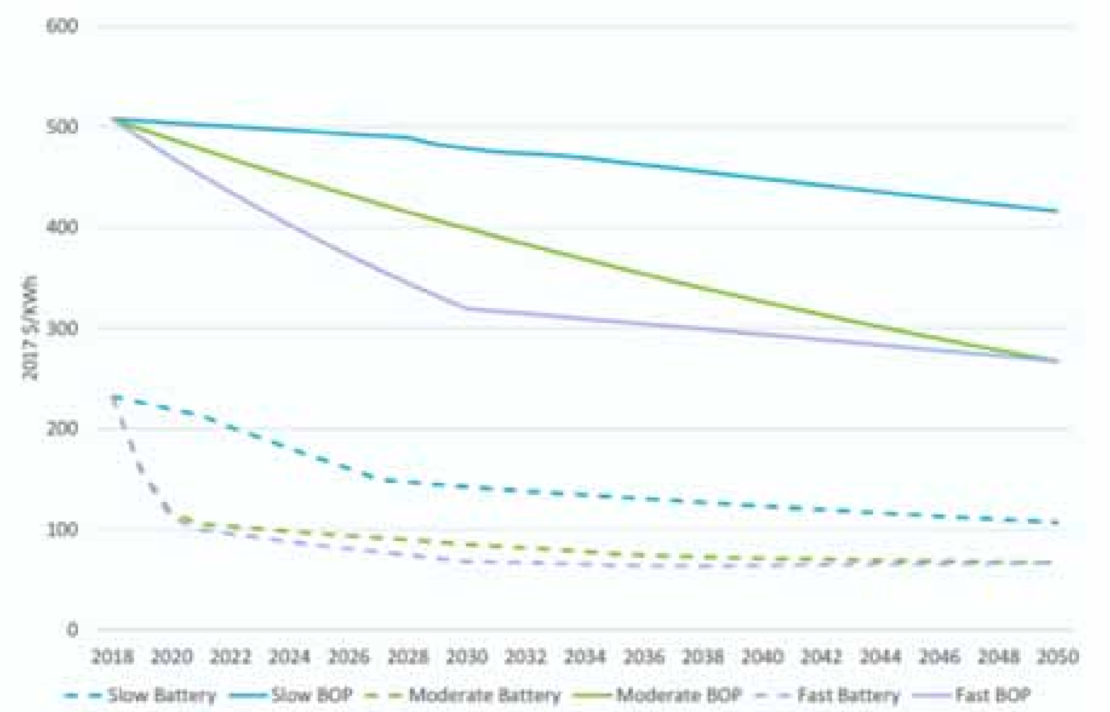
Residential battery storage capacity in Australia is forecast to reach around 2500 MW by 2029 under a neutral growth scenario. However, if the price of battery storage decreases more quickly, then consumer purchases of battery storage may accelerate, as can be seen in Figure B.11 and Figure B.12.

Figure B.11: Capacity of residential battery storage in Australia by scenario



Source: Graham et al. *Projections for small scale embedded energy technologies*, CSIRO, June 2019, pp. 49.

Figure B.12: Assumed capital costs for battery storage installations by scenario



Source: Graham et al. *Projections for small scale embedded energy technologies*, CSIRO, June 2019, pp. 23-24.

Note: BOP stands for balance of plant costs that are assumed to be upfront costs. They do not account for degradation or the cost of disposal at the end of life of the battery.

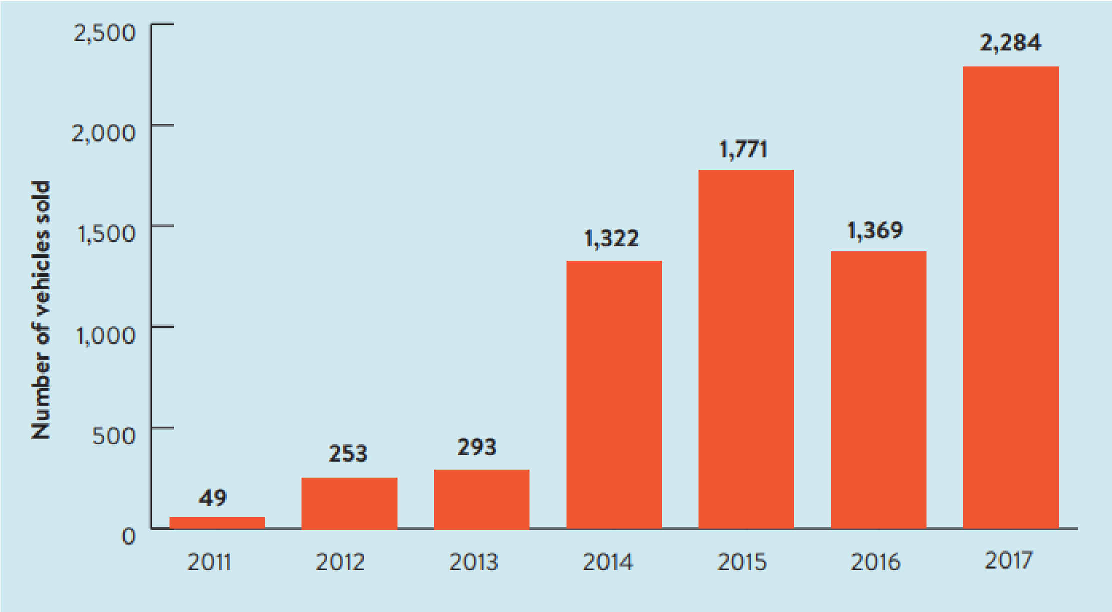
B.3 Electric vehicle trends

Consumers can use electric vehicles (EVs) as an alternative to internal combustion engine (ICE) vehicles that run on petrol. Because an EV is powered by a large battery, consumers can potentially use EVs to interact with the grid in a similar way as they can with battery storage.

As can be seen in Figure B.13, consumer uptake of EVs has been lower than that of solar PV and battery storage in Australia. Major factors that have inhibited EV uptake thus far include concerns regarding the distance that can be travelled per EV charge, the purchase cost when compared to petrol or diesel vehicles, the accessibility of charging infrastructure and the reliability of electric vehicle technology.[225]

225 ClimateWorks Australia, *The state of electric vehicles in Australia*, June 2018, p. 18.

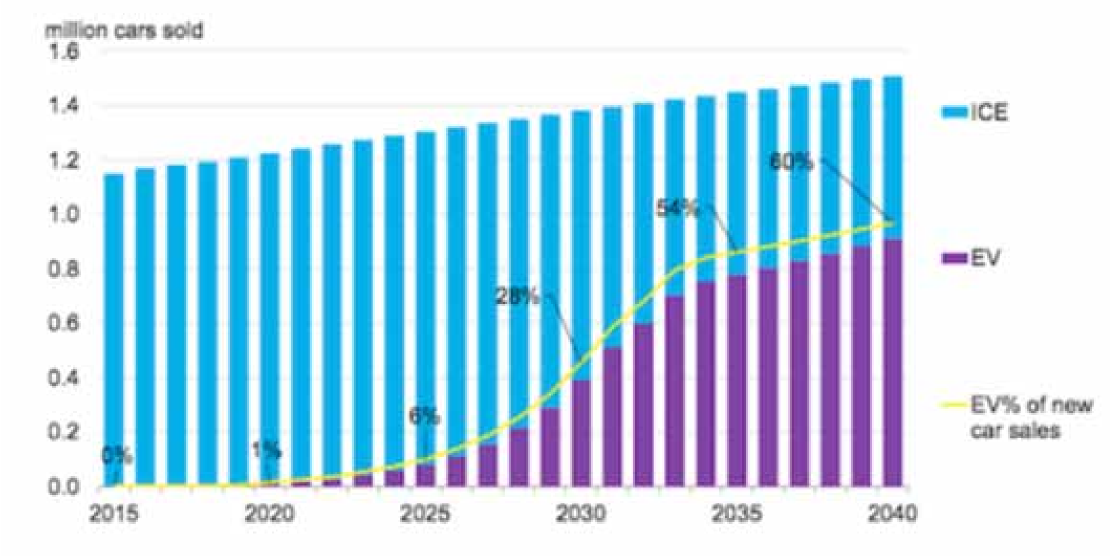
Figure B.13: Electric vehicle sales in Australia, 2011-2017



Source: ClimateWorks Australia, *The state of electric vehicles in Australia*, June 2018, p. 6.
Note: This chart includes an estimate of Tesla EV sales.

The shift to EVs is forecast to occur relatively quickly in Australia after 2025, with over 50% of new Australian car sales forecast to be for EVs in 2035.

Figure B.14: Long-term passenger vehicle sales for Australia



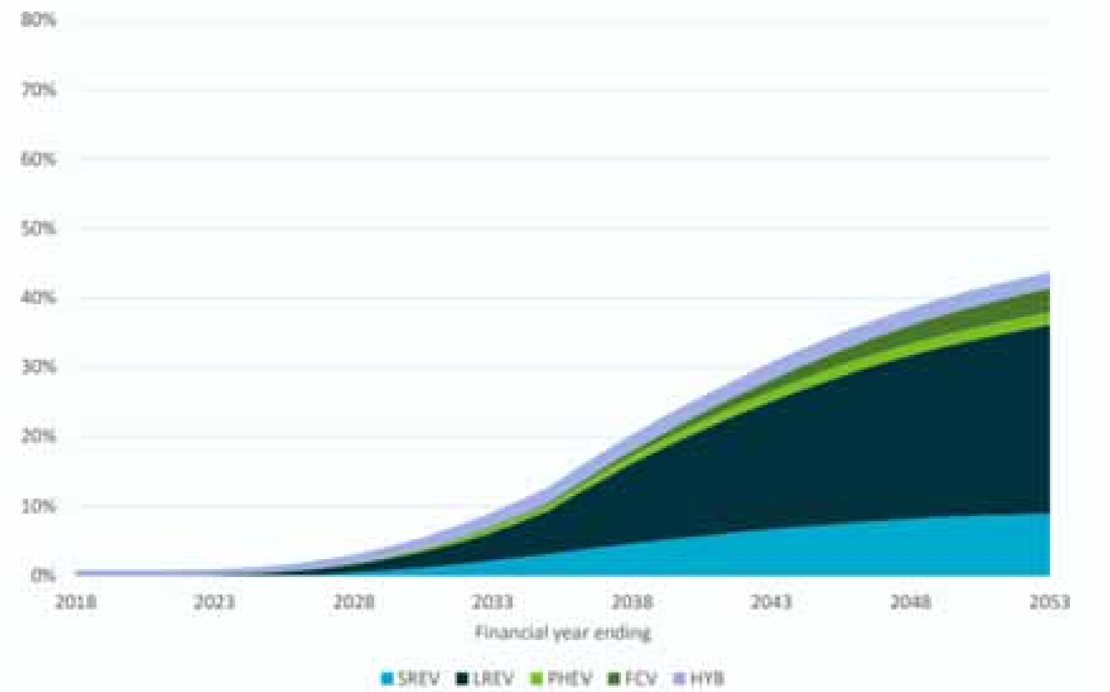
Source: Bloomberg NEF. Accessed via https://reneweconomy.com.au/australia-starts-slow-on-evs-but-could-overtake-global-market-53680/

Note: ICE stands for internal-combustion engine cars that use petroleum.

It would take a bit longer for these projected sales figures to translate into high rates of EV ownership in Australia. By 2038, more than 1 in 5 consumer vehicles are expected to be EVs.[226]

226 Including hybrid vehicles.

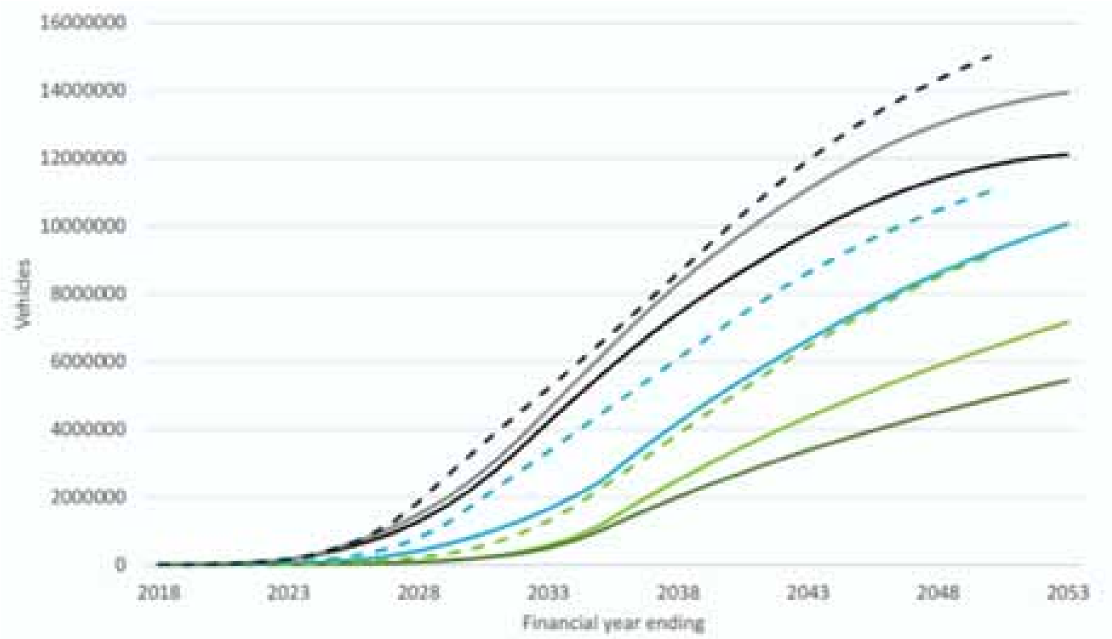
Figure B.15: Share of non-internal combustion vehicles in the Australian vehicles market



Source: Graham et al. *Projections for small scale embedded energy technologies*, June 2019, pp. 52.

Note: This figure is a neutral scenario. SREV stands for short range electric vehicle, LREV stands for long range electric vehicle, PHEV stands for Plug-in hybrid electric vehicle, FCV stands for fuel cell vehicle, HYB stands for hybrid electric vehicle (which does not charge from the grid)

Figure B.16: Number of electric vehicles in Australia by scenario



Source: Graham et al. *Projections for small scale embedded energy technologies*, June 2019, pp. 56.
Note: Electric vehicles in this chart includes short range, long range and plug-in hybrid electric vehicles.

B.4 Smart thermostats and energy management device trends

Consumers can use smart thermostats and energy management devices to see and adjust their energy consumption. With smart thermostats, consumers can automate their energy consumption, which in turn can affect how consumers use the energy generated or stored by their DER.[227] Energy management devices can also show consumers how much power is being generated by their DER, which can help them to decide how to manage their DER and grid usage at any given time.[228]

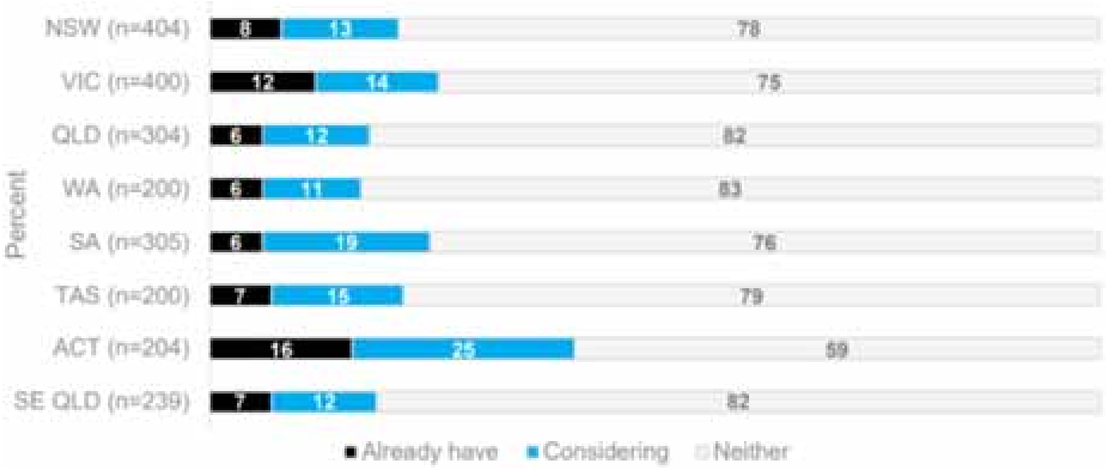
Smart thermostats and energy management devices are not widely used at present in the NEM; however a recent ECA survey indicated that consumers are increasingly considering purchasing these devices.[229]

227 The Zen Thermostat is an example of this. For more details, see https://zenecosystems.com/zenthermostat/

228 Blake Matich, *Empowering consumers: Wattwatchers aims to harness data to make PV pay*, 6 August 2019, https://www.pv-magazine-australia.com/2019/08/06/empowering-consumers-wattwatchers-aims-to-harness-data-to-make-pv-pay/

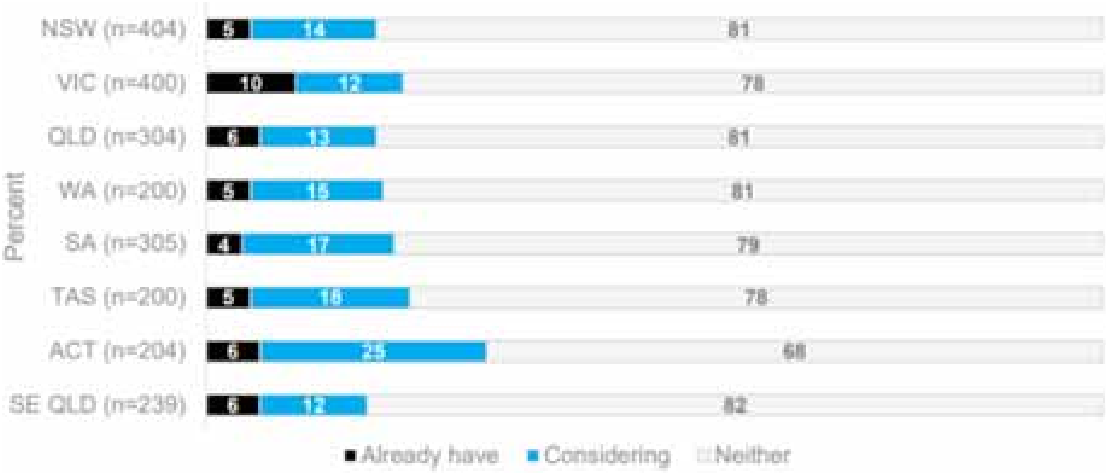
229 Source: ECA, 'Energy Consumer Sentiment Survey', June 2019, p. 27, 35

Figure B.17: Consumer ownership and interest in smart thermostats



Source: ECA, 'Energy Consumer Sentiment Survey', June 2019, p. 33

Figure B.18: Consumer ownership and interest in home management



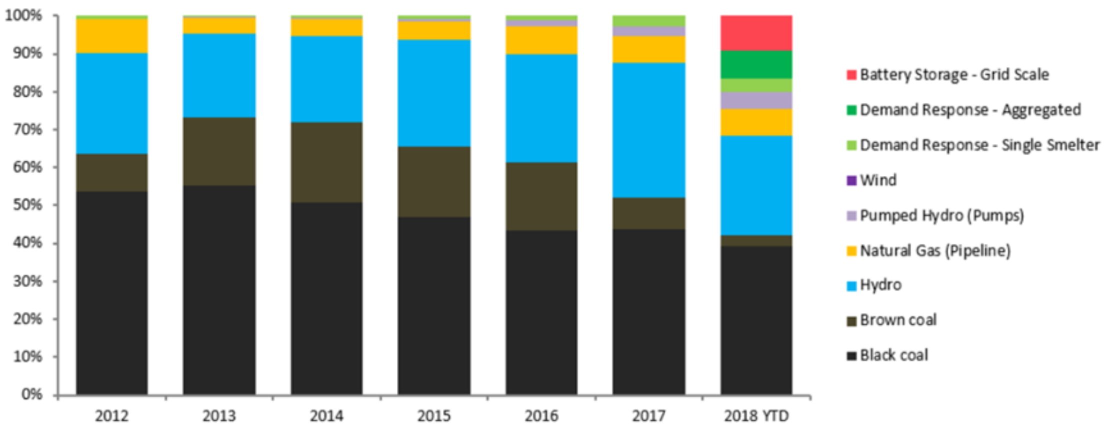
Source: ECA, 'Energy Consumer Sentiment Survey', June 2019, p. 35

B.5 Small customer participation in virtual power plants and demand response

Consumers with more active forms of DER (meaning some form of battery storage or demand response) can participate in a virtual power plant (VPP), meaning a retailer or other type of aggregator can bundle their DER-produced or stored electricity along with that of other consumers and then sell this energy. AGL[230], Tesla[231] and Simply Energy[232] are several parties that offer consumers the opportunity to participate in a VPP.

Demand response is another option that is available to consumers, including through a VPP. Through demand response, consumers can reduce their reliance on the grid and consume energy produced by their DER instead, which can ease demand pressures on the grid or provide the grid with frequency support. Figure B.19 shows how aggregated forms of demand response emerged to provide Frequency Control Ancillary Services (FCAS) support to the grid during 2018.[233]

Figure B.19: Where the NEM's Contingency FCAS comes from



Source: Matt Grover, *Demand Response is Disrupting Australia's Ancillary Services Markets*, 14 June 2018, accessed via https://energysmart.enelxnorthamerica.com/demand-response-disrupting-australias-ancillary-services-markets

Note: Sum of R6, R60, R5 FCAS. Enabled MWh (NB: not 'energy supplied') by technology type.
Calendar years: 2017 to 30 September (pre EnerNOC and Hornsdale PR). 2018 to 31 May 2018.

B.6 Stand-alone power systems

DER may also facilitate consumers at the edges of the grid disconnecting from it and setting up a stand-alone power system (SAPS). SAPS can incorporate different types of DER as the main power source for the consumer.[234] For these customers, switching to a SAPS can provide them with decreased costs and increased reliability, while also reducing the costs other consumers incur in maintaining distribution network infrastructure.

230 For more details, see: https://www.agl.com.au/solar-renewables/projects/power-in-numbers and https://www.pv-magazine-australia.com/2019/06/13/agls-new-virtual-power-plant-to-cover-four-states/

231 For more details, see: https://www.tesla.com/en_AU/sa-virtual-power-plant

232 For more details, see:https://www.simplyenergy.com.au/energy-solutions/battery-storage/south-australian-virtual-power-plant-vpp

233 Matt Grover, *Demand Response is Disrupting Australia's Ancillary Services Markets*, 14 June 2018, https://energysmart.enelxnorthamerica.com/demand-response-disrupting-australias-ancillary-services-markets

234 Chris Gilbert, *Edge of grid, end of line?*, 18 October 2018, https://www.energynetworks.com.au/news/energy-insider/edge-grid-end-line

The AEMC has recently provided recommendations for regulatory changes related to stand-alone power systems through DNSPs or t hrough a third party. As a result, we may see increasing use of SAPS to supply customers on the fringes of the grid. ENA and CSIRO predicted that new regulatory arrangements could lead to up to 27,000 rural customers adopting SAPS and disconnecting from the grid.[235]

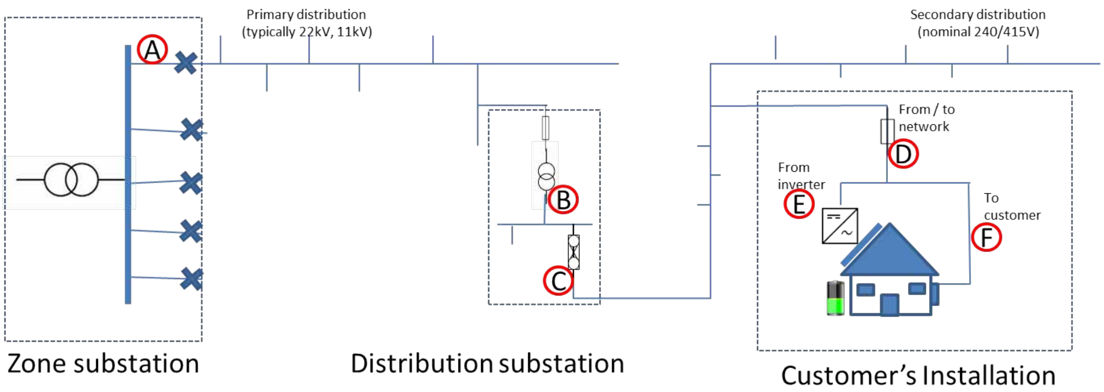
235 ENA and CSIRO, *Unlocking value: Microgrids and stand alone systems*, October 2016, pp. 2-3

C VISIBILITY OF LOADS AND VOLTAGES

In order to inform our review the AEMC, through and with the assistance of the ENA, asked Australian DNSPs about the load and voltage information that they capture on their primary (typically 11kV and 22kV) and secondary (LV) distribution networks, including the comprehensiveness of the information, the sampling period and the retention period. Responses were received from distributors in all mainland states and from the ACT. The responses are summarised in this appendix.

The completeness column reflects the amount of information captured at the location and the proportion of assets over which it is captured. It does not reflect any judgement about the amount of information that should be captured.

Figure C.1: Locations



Source: AEMC

Table C.1: Ergon Energy (Qld)

LOCATION	COMPLETE-NESS	TREND	COMMENTS
A. Zone substation feeder panel	●	→	• More than 95% of zone and Sub transmission substations have SCADA monitoring. • Voltage and current recorded • Updated automatically whenever there is a change. • Data is held for more than 10 years
B. Distribution substation transformer	◔	↑	• Approximately 3.5% of distribution transformers are monitored • Sites selected to towards the end of feeder or regulator sections. (Feeders can be 11kV,22kV or 33kV) • 10 minute average voltage, unbalance and total harmonic distortion. Events also recorded. • Read 1-4 times per day. • Program to install additional monitoring, subject to AER approval. • New padmounts will have monitors.
C. LV circuit	○	→	• No permanent monitoring.
D. Customer connection	◔	↓	• Generally no, although Ergon has access to a very small number of customer meters that provide load and voltage data. • Data access expected to reduce as ring-fencing arrangements are put in place. • Relatively low penetration of smart meters
E. Inverter exports	○	→	• Data not available to Ergon • (note that some customers have access to the data directly through their inverter's internet connection).

LOCATION	COMPLETE-NESS	TREND	COMMENTS
F. Customer consumption (including self-generation)	○	→	

Source: Ergon Energy

Table C.2: **Energex (Qld)**

LOCATION	COMPLETE-NESS	TREND	COMMENTS
A. Zone substation feeder panel	●	→	• B-C phase voltage • Current (amps) at the feeder • Power and reactive power at the zone transformer. • Updated whenever a parameter changes. • Kept at least 7 years
B. Distribution substation transformer	◕	↑	• Around 40% of distribution transformers have monitoring of phase-neutral voltages, apparent, real and reactive loads. • Rolled out to areas with most customers, and beginning, middle and end of 11kV feeders first to maximise usefulness. • 10 minute averages collected automatically • Stored locally and pushed once a day to centralised database. • Majority of new substations will have monitoring.
C. LV circuit	○	→	• No permanent monitoring
D. Customer connection	◔	↑	• Customer settlement data available • Very small penetration of smart meters at this stage • 1-2% of sites have separate monitoring. Monitoring typically

LOCATION	COMPLETE-NESS	TREND	COMMENTS
			targets problematic or study areas.
E. Inverter exports	○	→	• Data not available to Energex • (note that some customers have access to the data directly through their inverter's internet connection)
F. Customer consumption (including self-generation)	○	→	

Source: Energex

Table C.3: Essential Energy (NSW)

LOCATION	COMPLETE-NESS	TREND	COMMENTS
A. Zone substation feeder panel	●	→	• Data held for 85% of sites • Mix of SCADA and metering • 5 min instantaneous values (SCADA) or 15min average metering • Data generally held indefinitely.
B. Distribution substation transformer	○	→	• 10-20% of sites have maximum demand indicator with a lazy needle that measures the peak demand (in amps) since they were last read • Read 4 yearly or on an ad-hoc basis • small amount of monitoring at 0.014% - around 20 out of 140,000 – with metering at 15min intervals
C. LV circuit	○	→	
D. Customer connection	◔	↑	• Revenue metering – generally energy only but kVAr if required by the tariff • 7% smart meters, 93% quarterly energy

LOCATION	COMPLETE-NESS	TREND	COMMENTS
			• Interval meters read every 24-48 hours. Others read every 3 months.
E. Inverter exports	◔	→	• The 7% smart meter customers have the ability to disaggregate exports from inputs based on the tariff register • Data not used in BAU planning
F. Customer consumption (including self-generation)	◔	→	• As for E above (and D where there is no inverter).

Source: Essential Energy

Table C.4: **Ausgrid (NSW)**

LOCATION	COMPLETE-NESS	TREND	COMMENTS
A. Zone substation feeder panel	●	→	• Voltage and single phase load recorded • Near real time data capture with dead band and triggers for update • Read continuously, every 5 to 15 minutes • Future substations will record 3 phase load
B. Distribution substation transformer	◑	↑	• 17% have remote monitoring for voltage and load information. Real time monitoring with dead band. Reading updated when dead band threshold crossed. Can be interrogated for additional information. • Since 2009, new kiosk substations were installed with remote monitoring. • Algorithms used to estimate loads based on customer consumption, GIS and other information

LOCATION	COMPLETE-NESS	TREND	COMMENTS
			available. Estimates confirmed by measurement before works. • 60% have a manually read maximum demand indicator (lazy needle stays at highest demand until reset), read when staff visits site – typically once or twice a year. • Data stored indefinitely.
C. LV circuit	◑	↑	• Remote monitoring where installed (see above – 24% of circuits and rising) • Temporarily installed equipment for load and voltage surveys (every year for sites that are nearing overload) • Temporarily installed equipment is a mix of once off measurement and 15 minute interval data, depending on the equipment.
D. Customer connection	◔	↑	• Revenue metering data only – typically kWh. Approx. 22% interval meters, 70% accumulation meters, 8% smart meters. • Around 0.01% of sites have customer installed monitoring equipment, connected via a web interface. 5 minute average voltage and energy consumption available. • Temporary power quality devices installed where there have been customer complaints and moved around as required – 0.004% of sites.
E. Inverter exports	◔	→	• Gross connected meters, for kWh only. Around 0.5% of sites. Data collected every 90 days. •

LOCATION	COMPLETE-NESS	TREND	COMMENTS
			• Ad-hoc customer installed monitoring equipment (see D) also covers inverters.
F. Customer consumption (including self-generation)	◔	→	• As for E.

Source: Ausgrid

Table C.5: **Endeavour Energy (NSW)**

LOCATION	COMPLETE-NESS	TREND	COMMENTS
A. Zone substation feeder panel	●	→	• >95% coverage • SCADA data is collected continuously, with instant updates based on thresholds • Power quality data is 10 minute average • Used to better optimise target voltage levels while distribution transformer taps reset • At least several years of data available • Nearly full coverage
B. Distribution substation transformer	◔	→	• 1.8% of distribution substations. • Used to confirm suspected overloads • Both load and voltage recorded. • No plans to expand • 10 minute average data, polled 4 times daily.
C. LV circuit	○	→	
D. Customer connection	◔	↑	• Interval kWh data available for around 15% of customers via smart meters (increasing with smart meter uptake). •

LOCATION	COMPLETENESS	TREND	COMMENTS
			• 5 minute or 10 minute average data • Very limited voltage data • Increasing access dependent on negotiations with metering providers. • Future monitoring will depend on costs vs. benefits.
E. Inverter exports	◔	→	• 450 customer trial of purchased voltage and gross solar generation profile data from customer monitoring firms (Wattwatches, Solar Analytics). Trial to verify value and inform management of DER exports.
F. Customer consumption (including self-generation)	○	→	

Source: Endeavour Energy

Table C.6: **Evoenergy (ACT)**

LOCATION	COMPLETENESS	TREND	COMMENTS
A. Zone substation feeder panel	●	→	• Available for all feeders. • Automatically collected via SCADA • Sampling period very short (0.01s) • Updates every 15 seconds classes 1,2,3. Updates hourly class 0.
B. Distribution substation transformer	◔	→	• Only for SCADA enabled distribution substations. 150 of 4000 substations = 3%. • All new chamber substations monitored.
C. LV circuit	○	↑	• Just coming online. 85 units mapped. 50 units planned in the near future

LOCATION	COMPLETE-NESS	TREND	COMMENTS
			• 1000 devices to be installed over the next regulatory period.
D. Customer connection	◔	→	• Metering settlement data only available
E. Inverter exports	◔	↑	• Reposit boxes on 750 sites (of 23,000 inverter sites). Real time meter, solar and battery data. • Increasing at 50 customers per month.
F. Customer consumption (including self-generation)	◔	↑	• Reposit boxes on 750 sites (of 23,000 inverter sites). Real time meter, solar and battery data. • Increasing at 50 customers per month.

Source: Evoenergy

Table C.7: Ausnet (Victoria)

LOCATION	COMPLETE-NESS	TREND	COMMENTS
A. Zone substation feeder panel	●	→	• SCADA voltage and current stored • Online, near real time • Several seconds to several minutes sampling period • No fixed data termination date.
B. Distribution substation transformer	○	→	• Data derived through aggregation of customer connection metering data
C. LV circuit	○	→	
D. Customer connection	●	→	• 98% of sites provide full, remotely read data. Remainder not served by smart meters. • Type 1-4 meters – 15 minute data • Stored for 10+ years.
E. Inverter exports	○	→	
F. Customer consumption	○	→	

LOCATION	COMPLETE-NESS	TREND	COMMENTS
(including self-generation)			

Source: Ausnet

Table C.8: United Energy (Victoria)

LOCATION	COMPLETE-NESS	TREND	COMMENTS
A. Zone substation feeder panel	●	→	• Data available for all feeders • SCADA data continuous, updated based on trigger (e.g. 5A current flow change) • Power quality data available hourly • Disturbances – waveforms recorded based on disturbance trigger • Stored for no more than 10 years.
B. Distribution substation transformer	○	→	• Data derived through aggregation of customer connection metering data
C. LV circuit	○	→	• Data derived through aggregation of customer connection metering data
D. Customer connection	●	→	• Access to all net load (real and reactive, import and export) and voltage data from all customers with a United Energy smart meter • Delayed access for contestable or legacy meters • United Energy smart meter data automatically collected, multiple times a day. • 1 minute to 30 minute interval data.
E. Inverter exports	○	→	• Likely monitoring will need to take place in future.
F. Customer consumption	○	→	• Likely monitoring will need to take place in future.

LOCATION	COMPLETE-NESS	TREND	COMMENTS
(including self-generation)			

Source: United Energy

Table C.9: Jemena (Victoria)

LOCATION	COMPLETE-NESS	TREND	COMMENTS
A. Zone substation feeder panel	●	→	• Data available for all feeders • Load and voltage • Continuous, real time • Some sites have data back as far as 2013
B. Distribution substation transformer	○	→	• Data derived through aggregation of customer connection metering data
C. LV circuit	○	→	• Data derived through aggregation of customer connection metering data
D. Customer connection	●	→	• Access to load/energy(real and reactive), current and voltage data from all customers with a smart meter 98% of customers) • Data automatically collected, 4 hourly. • Energy - 30 minute interval data, current and voltage – 5 minute interval data. • Only logged for 1 year so far. Data can reside in meter for 200 days.
E. Inverter exports	○	→	
F. Customer consumption (including self-generation)	○	→	

Source: Jemena

Table C.10: Citipower and Powercor (Victoria)

LOCATION	COMPLETE-NESS	TREND	COMMENTS
A. Zone substation feeder panel	●	→	• Data available for all feeders • SCADA data continuous, aggregated to 5 minutes • Power quality data in 15 minute intervals • Power quality can be polled for harmonic and inter-harmonic data (both V and I) • Stored indefinitely, but >3 years old archived • Uses of data expanding in future
B. Distribution substation transformer	○	↑	• Data derived through aggregation of customer connection metering data • (Manual data loggers used at times) • Additional monitoring expected in future (DERMS project).
C. LV circuit	○	↑	• Data derived through aggregation of customer connection metering data • (Manual data loggers used at times) • Additional monitoring expected in future (DERMS project).
D. Customer connection	●	↑	• Access to load (real and reactive) and voltage data from all customers with a smart meter (>99% of customers) • Only settlement (consumption) data for contestable, legacy or non-interval meters (<1% of customers) • Data automatically collected, 4 hourly. • Mostly 30 minute interval data, but can be polled more frequently.

LOCATION	COMPLETE-NESS	TREND	COMMENTS
			• 5 minute settlement will mean more data • Proposal to install network devices at some type 1-4 meter sites to assist planning activities.
E. Inverter exports	○	→	• Very small number of legacy cogeneration sites only. • Meters generally owned by 3rd parties so only consumption/production data (not volts).
F. Customer consumption (including self-generation)	○	→	• Very small number of legacy sites • Consumption data only.

Source: Citipower and Powercor

Table C.11: SA Power Networks (SA)

LOCATION	COMPLETE-NESS	TREND	COMMENTS
A. Zone substation feeder panel	◕	↑	• 319 of 401 zone substations with SCADA • 3 second data collected. • 30 minute data stored long term. • Also approx. 6,500 SCADA field devices. • Data collected since 1996. Plan to expand coverage (see 2020-2025 reset proposal)
B. Distribution substation transformer	◔	↑	• 400 (of 77,000) sites, selected based on loading and DER. Even geographic spread. • Propose expanding to an additional 2,250 sites. • 10 minute interval data. • Most monitors installed in the last 2 years

LOCATION	COMPLETE-NESS	TREND	COMMENTS
			• Data used to model similar transformers and to give power quality visibility. • In future, intend to use in conjunction with other data sources to identify constraints.

C. LV circuit	○	↑	• Don't monitor individual LV circuits at the substation. However:
			• 150 "smart street lights" being installed:
			  • mid-line voltage monitoring
			  • 5 minute sampling. All data stored
			• Planning further work, but scale and type of deployment to be informed by trials.

D. Customer connection	◔	↑	• Only from VPP trial sites (Salisbury [111 sites], Tesla [320 sites]) – total 471 sites. Expected to increase to 1,000 Tesla sites later in 2019. • Will be trialling data from approximately 3,000 smart meters using two separate metering co-ordinators in 2nd half of 2019. • Data sampling period 5-10 minutes. • Expect to monitor 60,000 sites by 2025, and 130,000 by 2030 in line with reset proposal.
E. Inverter exports	○	→	• Salisbury VPP trial only (111 sites)
F. Customer consumption (including self-generation)	○	→	

Source: Powercor

Table C.12: Western Power (WA)

LOCATION	COMPLETE-NESS	TREND	COMMENTS
A. Zone substation feeder panel	●	→	• Data collected and goes back 10 years • 1-15 minute sampling period
B. Distribution substation transformer	○	→	• Less than 1% of distribution transformers telemetered • 1-15 minute sampling period • Data goes back 10 years
C. LV circuit	○	→	
D. Customer connection	◔	↑	• Interval kWh data available for around 5% of meters (increasing with rollout). • 15 minute or 30 minute average data • Settlement and billing data • Held indefinitely
E. Inverter exports	○	→	• Future collection of behind the meter data depends on future DER strategy and legislation
F. Customer consumption (including self-generation)	○	→	• Future collection of behind the meter data depends on future DER strategy and legislation

Source: Western Power

D DEVELOPMENT OF CONSUMER ENGAGEMENT APPROACHES BY JURISDICTION

The AER monitors consumer engagement activities through the Consumer Challenge Panel and its ongoing engagement with stakeholders. The AER comments in its decisions on any shortcomings that it identifies from an expenditure proposal that reflect weaknesses in consumer engagement.[236]

AER commentary as part of the previous round of electricity distribution revenue determinations highlighted that the networks had generally taken important initial steps to engage with consumers, but there were many opportunities for improvement. More recently, the AER has broadly commended the networks for their proactive engagement with consumers to better understand and incorporate their views and preferences into the proposals. As discussed in Chapter 6, these positive developments will help to smooth the transformation of the energy sector and enable consumers to engage with energy markets in new and exciting ways.

This 'before and after' AER and Consumer Challenge Panel commentary for each electricity network distribution business, by jurisdiction, is highlighted below. Although views expressed by the AER and Consumer Challenge Panel are generally subjective, the commentary is a measure of how distribution network businesses have progressed their consumer engagement approaches over time. Energy Networks Australia and CSIRO recognised the need for industry-wide engagement tracking and evaluation in developing the 2016 Customer Engagement Handbook:[237]

> There is the potential to develop a coordinated annual evaluation of broad engagement practices using several instruments that may be scaled up over time. This could include an annual inventory of engagement methods and longitudinal evaluation of engagement practice, to allow the industry to track progress and changes in engagement outcomes over time and across the industry.

D.1 New South Wales

The AER found in its 2015 round of decisions that the three New South Wales electricity distributors had not provided consumers with sufficient opportunity to influence their processes.[238]

In contrast, Essential Energy won the ENA's 2018 Annual Award for consumer engagement on its 2019–24 Regulatory Proposal:[239]

236 AER, Better Regulation: Consumer engagement guideline for network service providers, November 2013, p. 12.

237 See: https://www.energynetworks.com.au/sites/default/files/sharing_customer_engagement_practice_july_2016.pdf

238 AER, Ausgrid distribution determinations 2015–19, Final decision: Overview, April 2015, p. 18; AER, Essential Energy distribution determinations 2015–19, Final decision: Overview, April 2015, p. 18; AER, Endeavour Energy distribution determinations 2015–19, Final decision: Overview, April 2015, p. 17.

239 See: https://www.energynetworks.com.au/news/energy-insider/innovation-and-engagement-key-energy-future

> … with more than 3,000 customer interactions, Essential Energy demonstrated its commitment to ensuring the views of its regionally, culturally, demographically and economically diverse customer base were accurately and meaningfully reflected in its proposal. … The winner showed they had proactively engaged with their consumers to better reflect their views and priorities and allow that to shape services.

The Consumer Challenge Panel submitted that Essential Energy:[240]

> … [was] proactive in addressing consumer concerns and they responded more holistically to consumer and stakeholder input, as well as being prepared to have the 'tough conversations' and to seek solutions. [Essential] has effectively integrated consumer and stakeholder input into all aspects of its regulatory proposal and has effectively applied input that they have sought and heard.

Regarding Endeavour Energy, the AER recently said:[241]

> The significant advances Endeavour has made in its consumer engagement since our 2015 decision has been widely acknowledged by key consumer groups. After submission of its 2019–24 initial regulatory proposal in April 2018, Endeavour continued to engage with a number of stakeholders on identified areas of contention.

Ausgrid acknowledged the need to improve its consumer engagement, and took significant steps in-between its recent initial and revised proposals:[242]

> In line with suggestions from customer advocates and the AER in its Draft Decision, we are evolving our approach to engagement, to better integrate customer preferences into our strategy and business decisions. We believe that being more transparent and inclusive will improve our decision making and improve customer outcomes.

This change in approach was well-received by the AER:[243]

> In contrast to comments received in response to Ausgrid's initial proposal, consumer groups responded generally positively in their submissions on Ausgrid's revised proposal, noting a shift in Ausgrid's engagement style in pursuit of developing a revised proposal that could be supported by key consumer groups.

… and the Consumer Challenge Panel:[244]

> … worked closely with ECA, PIAC and EUAA to develop a list of commitments made by Ausgrid through the latter stages of the engagement process that we believed

240 CCP, CCP10 Response to AER Issues paper and revenue Proposals for NSW Electricity Distribution Businesses 2019-24, 8 August 2018, p.6, p.89.

241 AER, Endeavour Energy distribution determination 2019–24, Final decision: Overview, April 2019, p. 19.

242 Ausgrid, Revised regulatory proposal 1 July 2019 to 30 June 2024, January 2019, p. 14.

243 AER, Ausgrid distribution determination 2019–24, Final decision: Overview, April 2019, p. 21.

244 CCP, CCP10 Response to the Ausgrid Revised Regulatory Proposal 2019-24 and AER draft determination, January 2019, pp. 26–27.

> consumers expected to see reflected in Ausgrid's Revised Proposal. Our goal in developing the commitments was to embed customer engagement in day-to-day operations… CCP10 congratulates Ausgrid on creating the opportunity (albeit very late in the 2019–24 process) to engage with customers and the AER in a new, more constructive and collaborative way. CCP10 acknowledges that Ausgrid's Revised Revenue Proposal reflects many commitments that are important to customers…

D.2 Australian Capital Territory

The AER found in its April 2015 decision that Evoenergy (formerly ActewAGL) had not engaged with consumers until after it submitted its regulatory proposal.[245]

In April 2019, the AER said:[246]

> Our impression is that Evoenergy's consumer engagement processes, including its increased efforts to engage with consumers prior to submission of its initial regulatory proposal in January 2018, have improved significantly in recent years. … Evoenergy's consumer engagement in the preparation of its 2019–24 initial and revised regulatory proposals has generally been well received by stakeholders, but there is room for ongoing improvement, particularly in terms of embedding consumer engagement into business-as-usual operations.

D.3 Queensland

In its October 2015 decisions, the AER commended Energex and Ergon Energy for their progress on consumer engagement, but said it expected these networks to develop their approaches and become more 'sophisticated' in developing their next regulatory proposals.[247]

In 2018 the Consumer Challenge Panel commended Energy Queensland (Energex and Ergon Energy) for the engagement approach:[248]

> We had some concerns that EQ's engagement 'started in earnest' later than its peers, and the quality of some engagement activities has been patchy with unclear information and overstated narratives in areas such as IT. The latter stages of engagement leading to the production of the Draft Plan however have been effective, well-attended and engaging. We also note that the sessions have been very well attended and supported by the CEO and senior executive team.

245 AER, ActewAGL (now Evoenergy) distribution determination, Draft decision: Overview, p. 68

246 AER, Evoenergy distribution determination 2019–24, Final decision: Overview, April 2019, p. 21.

247 AER, Ergon Energy distribution determination 2015–20, Final decision: Overview, October 2015, p. 52; AER, Energex distribution determination 2015–20, Final decision: Overview, October 2015, p. 48.

248 Consumer Challenge Panel (CCP14), Response to the Energy Queensland (Energex and Ergon Energy) 2020-25 Draft Plan and Early Engagement, September 2018, p. 23

D.4 South Australia

In its October 2015 decision, the AER commended SA Power Networks for its proactive approach to consumer engagement, but found SA Power Networks had inappropriately used willingness to pay studies to justify higher network expenditure. Some stakeholders had accused SA Power Networks of 'push polling'. SA Power Networks even argued at the time:[249]

> … the AER should place little or no weight on the stakeholder submissions and CCP advice that were critical of SA Power Networks' customer engagement program because they were either largely anecdotal in nature, unsubstantiated or technically lacking.

In contrast, SA Power Networks was a finalist for both the 2019 and 2018 Consumer Engagement Awards for its community engagement on its 2020–25 Tariff Structure Statement and 'Deep Dive Workshop Program' leading up to its 2020–25 regulatory proposal, respectively.

The Consumer Challenge Panel recently commended SA Power Networks:[250]

> … for this early engagement approach that set a new benchmark in quality of information, commitment by many staff and the availability of a wealth of feedback from its customers and the wider SA community. This was facilitated by best practice community engagement through their Customer Consultative Panel (SAPN CCP) and Reference Groups. The SAPN 'Talking Power' website provided a comprehensive and effective platform for encouraging and recording engagement with their community and customers – this is perhaps one of the most effective uses of websites that we have seen in this round of regulatory resets for electricity distributors.

However, the Consumer Challenge Panel found subsequent engagement by SA Power Networks was disappointing, and ultimately the proposal submitted to the AER does not adequately demonstrate genuine transparent consumer engagement:[251]

> … whilst there was sector-leading engagement up until the Draft Plan, for which we commend SAPN, subsequent engagement has been disappointing. … So, after a very effective start, SAPN seemed to 'close shop' and not reflect what we consider to be the many valid concerns of consumers. We did not get the feeling that SAPN was interested in considering whether they could meaningfully 'move their position' or take steps to respect the concerns by stakeholders by seeking to further engage with concerned groups on major issues.

249 AER, SA Power Networks distribution determination 2015–20, Final decision: Overview, October 2015, p. 48.
250 Consumer Challenge Panel (CCP14), Advice to the AER on the SA Power Networks 2020-25 Regulatory Proposal, May 2019, p. 8.
251 Consumer Challenge Panel (CCP14), Advice to the AER on the SA Power Networks 2020-25 Regulatory Proposal, May 2019, p.5, p.10.

D.5 Tasmania

In its April 2017 decision, the AER considered TasNetworks had taken important steps to engage with its customers in a very positive manner, and noted stakeholder views that it could better show how feedback had been taken into account in its regulatory processes.[252]

In its April 2019 decision, the AER said:[253]

> TasNetworks was one of the first network businesses to develop an early consumer engagement framework, which it undertook prior to submitting its electricity distribution regulatory proposal for the current regulatory control period. This included the release of a preliminary revenue proposal for consultation, which now sets the benchmark for all network service providers. … We consider TasNetworks continues to recognise the importance of consumer engagement and the value it delivers for the network business and customers. It has been one of a handful of network businesses that has commenced its engagement with consumers well in advance of submitting its regulatory proposal and appears to be responsive to customer feedback in shaping outcomes. This is reflected in the AER's Consumer Challenge Panel (CCP13) advice to us on TasNetworks' regulatory proposals. … We were particularly encouraged to see CCP13 confirm that post lodgement of its initial proposal, TasNetworks is to be commended for a committed, well planned and well executed consumer engagement process, particularly on its contingent project … Consistent with CCP13's advice, we accept that TasNetworks has undertaken a high quality consumer engagement process and is well informed of consumers' interests and concerns in framing its revenue proposals.

D.6 Victoria

In its May 2016 decisions, the AER broadly stated that although the Victorian distributors had taken important steps to engage with their customers, it was critical of their failure to consult on changes in positions that led to significant increases in network charges between the initial and revised proposals. Some stakeholders submitted that these networks had 'opportunistically' taken advantage of a separate Australian Competition Tribunal decision relating to the cost of debt.[254]

In contrast, for the 2018 Consumer Engagement Award, the five Victorian distributors were a finalist on their joint consultation on Network Pricing Design.[255] As discussed in section 6.1, Jemena was the winner of the 2019 Consumer Engagement Award for its People's Panel citizens' jury in Victoria (as well as its Gas Networks Deliberative Forum in NSW).

252 AER, TasNetworks distribution determination 2017–19, Final decision: Overview, April 2017, p. 55.

253 AER, TasNetworks distribution determination 2019–24, Final decision: Overview, April 2019, pp. 21–23.

254 AER, AusNet Services Distribution determination, Final decision: Overview, May 2016, p. 53; AER, CitiPower Distribution determination, Final decision: Overview, May 2016, pp. 52–53; AER, Jemena Distribution determination, Final decision: Overview, May 2016, pp. 53–54; AER, Powercor Distribution determination, Final decision: Overview, May 2016, pp. 53–54; AER, United Energy Distribution determination, Final decision: Overview, May 2016, pp. 53–54.

255 See: https://www.energynetworks.com.au/news/energy-insider/innovation-and-engagement-key-energy-future

The Consumer Challenge Panel broadly said:[256]

> We consider that there has been a significant step change in the overall effectiveness of consumer engagement for all [Victorian] businesses since the consultation on the 2016–20 Regulatory Proposals. We commend the businesses for their willingness to adopt a range of innovative approaches to develop regulatory proposals that seek to better incorporate consumer perspectives in the regulatory proposal.

As discussed in section 6.1, AusNet Services is undertaking a trial of the New Reg Process. The Consumer Challenge Panel provided feedback on the Customer Forum's 'Initial Engagement Report':[257]

> Notwithstanding that the Customer Forum's ability to influence bill outcomes may be limited, we are impressed by the impact which the Customer Forum has already had in realigning AusNet Services business towards a more customer-centric mode of operation as a result of the customer experience negotiations between the Customer Forum and AusNet Services. … we congratulate AusNet Services for taking these important steps to deliver an improved customer experience for their customers. We agree that the actions undertaken and proposed by AusNet Services will be a significant step towards addressing customers' needs and expectations in both the short and longer term.

Specific to Jemena, the Consumer Challenge Panel says:[258]

> We observe that Jemena is at the forefront of both development and application of consumer engagement approaches. … With Jemena we have observed a willingness and capacity to listen to everything that customers have said and to respond appropriately. While there will always be asymmetry between the knowledge and technical expertise of network businesses and their customers, we are satisfied that this is unlikely to be of concern with JEN's ongoing engagement.

The Consumer Challenge Panel's recent commentary of CitiPower, Powercor and United Energy's engagement is less favourable:[259]

> We have generally encouraged the businesses on the paths that they have chosen, on the shared understanding that not every consumer engagement activity will prove successful. The businesses are on a steep learning curve, and much learning will come from trial and error. … It remains to be seen the extent to which consumer engagement will change the businesses' regulatory proposals, or influence their

256 Consumer Challenge Panel, Sub-Panel CCP17, Progress Report on Consumer Engagement by the Victorian Electricity Distribution Businesses for the 2021-2025 Regulatory Reset, March 2019, p. 23.

257 Consumer Challenge Panel (CCP17), Comments on the AusNet Services Customer Forum Interim Engagement Report, February 2019, p. 25.

258 Consumer Challenge Panel, Sub-Panel CCP17, Progress Report on Consumer Engagement by the Victorian Electricity Distribution Businesses for the 2021-2025 Regulatory Reset, March 2019, pp. 11–15.

259 Consumer Challenge Panel, Sub-Panel CCP17, Progress Report on Consumer Engagement by the Victorian Electricity Distribution Businesses for the 2021-2025 Regulatory Reset, March 2019, pp. 16–21.

ongoing 'business as usual' behaviour.

E LONG TERM TECHNICAL DEVELOPMENTS AND OPPORTUNITIES

Energy production in the NEM is dominated by synchronous coal fired generators. This fleet of baseload generators will start to reach the end of its technical life in around 2030.[260] While peak and intermediate synchronous generators, in particular hydro generators and potentially gas generators, are likely to remain in service well beyond the 2030s, the fact that they are peak and shoulder generators means that they may not always be on line to provide frequency support. It is possible that energy production and ancillary services will become dominated by asynchronous, inverter based generators like solar and wind, and inverter based storage like batteries.

Achieving real time energy balance currently relies on the properties of a synchronous generation fleet. Traditionally, if load is greater than generation generators slow down a little, consuming some of the energy stored in their rotating turbines, shafts and rotors, in turn causing a drop in the system frequency which automatically signals a need for more generation or, in extreme cases, less load.

With asynchronous generation and storage this does not necessarily have to be the case. If stored energy can be delivered quickly from asynchronous sources like batteries then more active and pre-emptive control may be possible. Alternatively, frequency could continue to be used to signal the need for more or less generation if the devices were programmed to provide a frequency response, or a hybrid model may be preferred, particularly during a transition.

Importantly, the change in energy storage – from rotating parts in large, centrally dispatched generators to distributed batteries may provide opportunities to improve resilience and reliability. Smaller and smaller segments of networks may become capable of forming grids and standing on their own, either permanently or for a period of time while the network is reconfigured and repairs are made.

E.1 Balancing energy

Energy delivered to customers and energy consumed by customers must be in balance at all times. From a system perspective, this means that the amount of energy being generated plus increases (or decreases) in stored energy must at all times equal consumption plus system losses.

It follows that any step change in consumption or generation must immediately result in a corresponding step change in the flow of energy to or from storage, until such time as generation and consumption can be brought back in to balance.

With traditional synchronous generators storage resides in instantly accessible rotational kinetic energy, as well as in very rapidly accessible energy stored in boilers, and in rapidly accessible energy stored in dams.

260 AEMO, Integrated system plan, June 2018, p.22.

Reciprocating engines and open cycle gas turbines, where online, can also respond relatively rapidly in order to bring generation and consumption back into balance.

Traditionally, the combination of behaviours from different synchronous machines allowed the power system to cope with network disturbances.

For example, historically in Victoria and NSW, if a coal fired generator tripped, so that system load was greater than generation, then other synchronous generators would start slowing down, releasing stored rotational kinetic energy. Control systems would sense the slowing frequency and open steam governors, very rapidly releasing energy stored in boilers and thereby increasing generation output for a number of minutes. At the same time, vanes on hydro generators might open, allowing columns of water to start speeding up, increasing output over a number of minutes, just as the energy stored in boilers in the form of steam pressure starts to be exhausted. Ramping of OCGT and reciprocating engines where available would provide additional support.

Coal fired and other synchronous power stations are likely to continue to dominate energy production in Queensland, NSW and Victoria until after 2030.[261] Frequency degradation is therefore likely to continue to be the dominant mechanism for signalling supply shortfalls for many years to come. However, over time as coal fired generation is retired and as the proportion of asynchronous generation increases, particularly at non-peak times, this technical and market dynamic must change if the need for synchronous machines is to be overcome.

A number of recent and current trials are looking at how best to balance energy in the absence of, or with limited availability of, synchronous generation.[262]

Large scale battery storage is also already being used for frequency support in some instances, both in response to frequency changes and in also response to externally initiated commands.[263] However, while battery storage can respond to frequency changes, unlike a turbine its frequency will not necessarily slow down when overloaded, unless it is programmed to do so.[264]

E.1.1 Emerging opportunities

Moving from centralised to decentralised generation may provide opportunities for more resilience at lower cost if technological and framework issues can be resolved.

261 AEMO integrated system plan, figures 13, 16 and 17.

262 For example, the *CONSORT Bruny Island battery trial*, the University of Tasmania's *Optimal DER Scheduling for Frequency Stability* project, the Australian National University's *Consumer energy systems providing cost-effective grid support* project, the Hydro Electric Commission's *King Island Renewable Energy Integration* project and *Rottnest Island water and renewable energy* project, PGWF's *Advance Energy Resources Wind, Solar and Battery* project and UNSW's *Addressing barriers to efficient renewable integration* project. See https://arena.gov.au/projects.

263 Aurecon, *Hornsdale Power Reserve Year 1 Technical and Market Impact Case Study*, pp.5-6.

264 An individual battery could be programmed to mimic a synchronous machine to the extent it can within technical limits but, while a large battery may store much more energy than a spinning turbine alternator, it is not able to deliver a significant portion of that energy in less than a second.

In the NEM, if system instability leads to an interruption, that interruption is normally widespread. Such interruptions can last from hours to days.[265]

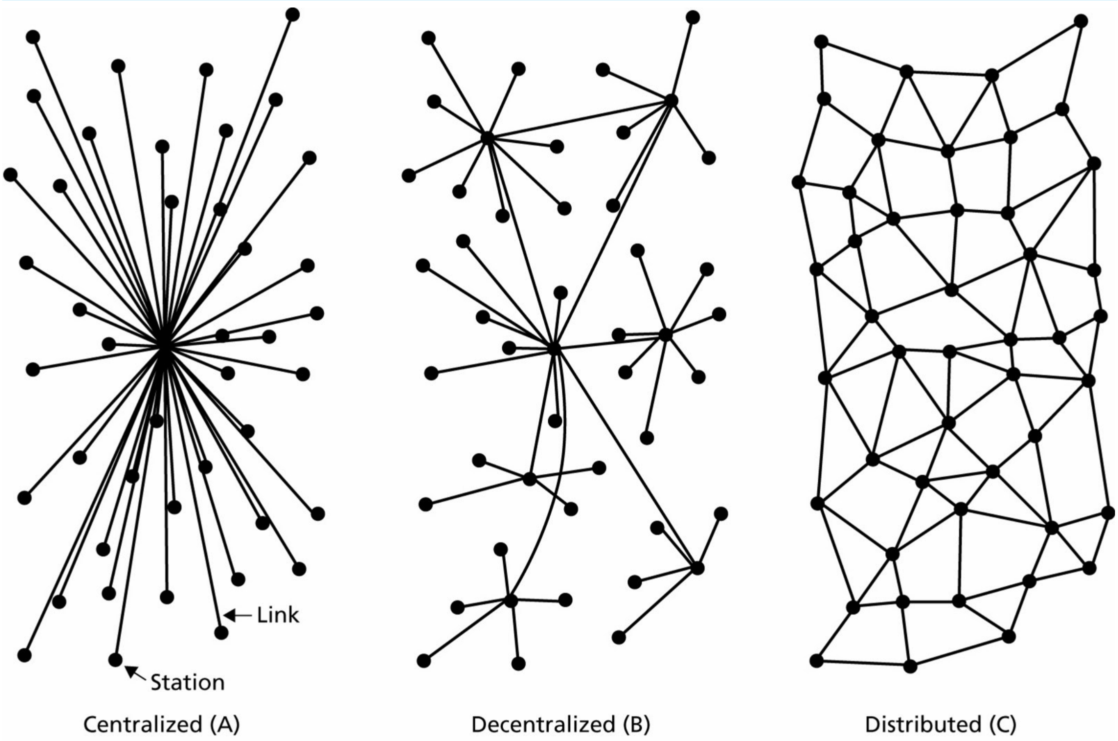
While the Commission does not know exactly how the power system will evolve, the following are potential conceptual models that may emerge as alternatives to, or augmentations of, centralised networks.

Decentralisation

Decentralised energy generation and storage could potentially, over time, provide greater local autonomy. Decentralised generation may also be used to limit the extent and duration of supply interruptions by allowing small areas, rather than whole states, to isolate themselves and self-supply for a period of time in the event of a major disturbance, reducing the extent of an outage and potentially also significantly reducing the time taken for restoration.

A conceptual illustration of decentralisation is shown below:[266]

Figure E.1: Decentralisation



Source: The RAND Corporation

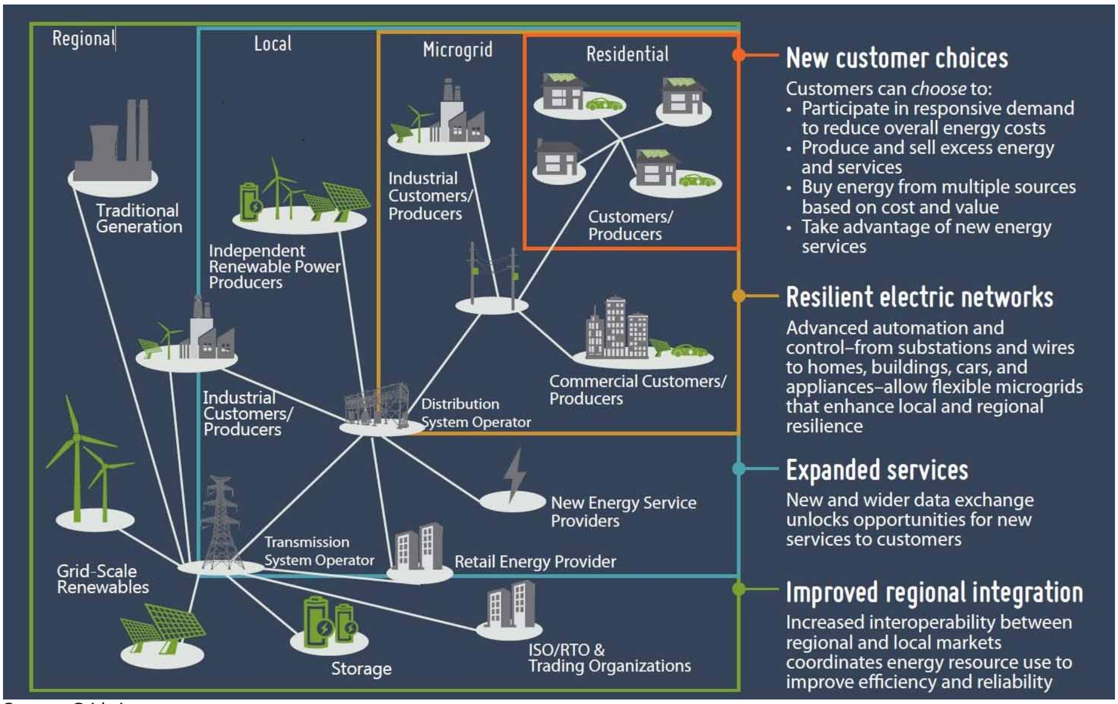
265 AEMO, Black System South Australia 28 September 2016 – Final report, March 2017, page 77 and DGA Consulting, International comparison of major blackouts and restoration, 5 May 2016, pp.5-7.

266 The RAND Corporation, Baran, P. *On Distributed Communications, Memorandum RM-3420-PR*., prepared for United States Air Force project Rand, Santa Monica, California, August 1964.

Nested common pool resources

Under a nested arrangement, which is a form of decentralisation, resilience is provided in layers. The outer layer might be the equivalent of a NEM region. Depending on the resources available, services and supply might be available at local (perhaps zone substation), microgrid or even individual customer level, at least for a period of time. The deeper the resource penetration, the greater the potential for local network resilience, as shown below:[267]

Figure E.2: Nested model



Source: Gridwise

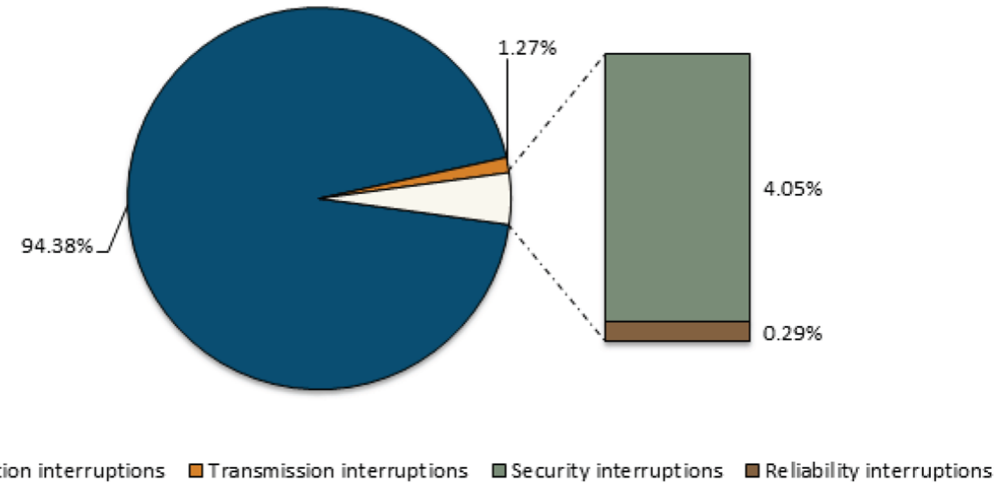
An advantage of a nested model is that it can improve service levels and provide access to markets at a local level, allowing consumers to better benefit from and share in the value of DER.

As the majority of supply interruptions are due to distribution network faults, as shown below,[268] lower level nesting also has the potential to significantly improve reliability in future if it can allow time for switching and repair on the primary distribution (generally 11kV or 22kV) network.

267 Gridwise architecture council, GridWise transactive energy infographics, https://www.gridwiseac.org/about/transactive_energy.aspx, accessed 16 July 2019.

268 Reliability panel AEMC, *Final report Annual market performance review 2018,* 04 April 2019, page xlvi.

Figure E.3: Sources of supply interruptions in the NEM from 2007/08 to 2017/18



Source: AEMC analysis based on publicly available information from AEMO's incident reports and the AER's RIN economic benchmarking spreadsheets

Note: With regard to outages on the distribution network in 2017/18, a number of distribution network service providers (DNSPs) have reported unsupplied energy data on a calendar year rather than financial year basis via the RIN. For these DNSPs, the data for the 2017 calendar year was treated as 2017/18 financial year data. The DNSPs reporting unsupplied energy on a calendar year basis are: ActewAGL (now Evoenergy), Endeavour Energy, Energex, SA Power Networks and TasNetworks.

F SHORT TERM ACTIONS TO INCREASE HOSTING CAPACITY

F.1 Voltage regulation background

Network voltage standards must complement equipment voltage standards so that connected equipment, including both network components and consumer appliances, can operate safely and correctly.[269] Jurisdictions therefore impose statutory limits on the steady state voltage range that distribution networks are allowed to supply, generally in accordance with Australian standards,[270] or a variant thereof.[271]

Traditionally networks were designed to send electricity one way. With a one way flow the voltage at the start of a circuit is always higher than at the voltage at the end of the circuit,[272] so the best way to set up voltage regulation was to keep voltages as high as allowable at the start of the circuit.[273] This provided the maximum headroom for downstream voltage drop on both the LV network and within a customer's premises, and also maximised the energy carrying capacity of the LV network and minimised losses. The voltage at the start of a circuit can also be set with more precision than the voltage at a customer's switchboard, due to the unknown distribution of loads along the circuit.

However, when energy flows in the reverse direction, then the voltage at the customer's premises must be higher than the voltage at the start of the circuit. This can lead to, or exacerbate, overvoltages if DER generation is not curtailed when voltage limits are reached, or if additional headroom is not created.

There is now substantial evidence of occasional voltage excursions outside of upper allowed limits,[274] and evidence that the number of excursions is increasing with increased residential solar penetration.[275]

Ideally DER generation should automatically curtail its output when the upper voltage limit is approached.[276] This would prevent DER driven over voltages from occurring. However,

269 See Chris Halliday and Dave Urquart, *Voltage and equipment standards misalignment*, the Electric Energy Society of Australia, Canberra, 2011 for a discussion of the need for aligning equipment and supply standards.

270 AS 60038, Standard Voltages and AS61000.3.100. For more details, see Standards Australia, *Electromagnetic compatibility (EMC) - Part 3.100: Limits - Steady state voltage limits in public electricity systems*, December 2011. The historical standard was AS 2926 (superseded).

271 See Naomi Stringer et al., *Data driven exploration of voltage conditions in the Low Voltage network for sites with distributed solar PV*, Peer reviewed for the 2017 Asia-Pacific Solar Research Conference, 2017, table 2. Also, see Queensland Government Department of Natural Resources, Mines and Energy, 'New statutory voltage limits for Queensland', viewed 26 August 2019, https://www.dnrme.qld.gov.au/energy/initiatives/statutory-voltage-limits.

272 in the absence of capacitive load

273 This would be determined under the most onerous normal conditions. High voltage feeders supply many high to low voltage transformers. Voltage drop along high voltage feeders varies with load and distance from source. Voltage drop within an individual transformer also depends on the load in that transformer, which may have a different load cycle to other transformers on the same high voltage feeder. This necessarily means that the voltage at the low voltage terminals of each transformer may vary significantly throughout each day and season, notwithstanding the voltage regulation schemes that are in place.

274 See Naomi Stringer et al., *Data driven exploration of voltage conditions in the Low Voltage network for sites with distributed solar PV*, Peer reviewed for the 2017 Asia-Pacific Solar Research Conference, 2017, pp. 7-11

275 Endeavour Energy, *Regulatory DEIP Dive - Endeavour Energy,* Presentations to the DEIP Dive forum, 6 June 2019, slide 6. See also SA Power Networks, *Maximising customer value from the network in a high-DER future,* Presentation for AEMC/ARENA Regulatory DEIP dive, 6 June 2019, slide 9.

276 Referred to as a "volt-watt" response.

evidence suggests that not all inverters are curtailing their output when upper limits are reached. Further, the upper voltage limit for inverter export under historical settings is sometimes outside of the top end of the standard voltage range[277]

While the majority of non-compliance is for over voltages, some under voltages are still present at some times. However recent changes to voltage standards, allowing lower minimum voltages, should see compliance rates for under voltages improve.[278]

F.2 Creating additional headroom

A number of options are available for increasing DER export capacity on low voltage circuits.

F.2.1 Changing the voltage standard

For the reasons cited above, low voltage networks tend to operate towards the high end of the allowed range.

Recent regulatory and standard changes have now lowered the bottom of the allowed voltage range. The old Australian Standard 2926 adopted a nominal phase to neutral system voltage of 240V, with a tolerance of +/- 6%, giving an allowed range of 226V to 254V. Most networks were designed to operate within this range and, in the absence of active intervention, remain so.

Most jurisdictions have now adopted a nominal voltage of 230V, consistent with the International Electrotechnical Commission (IEC) standard 60038 and with the Australian mirror standard 60038. IEC 60038 also allows for a +/-10% voltage range (207V to 253V), but Australia has generally adopted a +10%/-6% tolerance, giving an allowed range of 216V to 253V. The bottom end of this range is still far lower than the previous 226 volts. The lowering of the bottom end of the allowed voltage range means that voltages at the start of low voltage circuits can be lowered without necessarily impacting a distributor's ability to keep supply within the allowed voltage range.

In many cases simple measures can be implemented in order to lower network voltages, thereby creating additional export headroom.

F.2.2 Manually changing distribution transformer taps

Lowering fixed taps on distribution transformers to increase their transformation ratio (and therefore reduce their output voltage) will increase the hosting capacity of the low voltage network. Changing the fixed tap position itself is a very simple and quick exercise, but the distribution transformer must be de-energised in order to do so. There are cost associated with notifying and interrupting consumers, or with arranging alternative supply, are likely to greatly outweigh the cost

277 Ben Noone, *PV Integration on Australian distribution networks: Literature review*, Australian PV Association, 2013, Table 12.

278 Energex, *Distribution annual planning report 2018-19 to 2022-23*, December 2018, p. 152. According to Energex, "*the number of monitored sites that recorded under voltage outside of regulatory limits of 216.2 V was 0.81% for 2017-18. This means 0.81% of monitored sites recorded an exceedance of the lower limit for more than 1% of the time based on 10 minute averages.*"…"*The change to 230 volts will see the lower limit for low voltage move to 215 volts. This change is expected to result in the number of non-compliant sites reduce to virtually zero.*"

F.2.3 Changing settings for on load tap changers

Zone (and higher level) transformers can and do adjust their transformation ratios continuously, using on-load tapchangers, in order to maintain system voltage levels under different loads and conditions. Voltage regulation settings for zone transformers could be adjusted to allow greater headroom for DER exports, subject to any tapping range limitations on the zone transformer itself.

F.2.4 Reactive power

LV export capacity can also be enhanced through absorbing reactive current from the LV network. Network impedance is predominantly also reactive, and reactive current drawn through reactive impedance generates negative voltage. Modern inverters are able to absorb reactive current, and AEMO have recommended default enablement of inverter "Volt-Var" functionality in order to absorb reactive current when voltage levels are towards the high end of the allowed range. [279] These requirements are set out in clause 4.10.2 of Energy Networks Australia's (ENA's) national connection guidelines.[280]

Increasing reactive current will however increase system losses and reduce thermal capacity, including in upstream elements.[281] At low voltage, inverters are being constrained off due to voltage limits well before low voltage thermal limits are reached, so that the thermal capacity limit may not be relevant at this level of the system.

F.2.5 Other options

Capital intensive options, such as extending transformer tapping ranges, installing on-load distribution transformer tap changers, using larger cross section wires and cables, or increasing the number of circuits are also possible, but for existing network elements the cost of replacing primary network elements like transformers is likely to be prohibitive in most circumstances. Standard designs could however potentially be updated to incorporate cost effective options for new installations.

279 AEMO, *Technical Integration of Distributed Energy Resources - Improving DER capabilities to benefit consumers and the power system A report and consultation paper*, April 2019, table 1 and pp. 50-51.

280 ENA, *National Distributed Energy Resources Grid Connection Guidelines - Technical Guidelines for Low Voltage EG Connections*, ENA DOC 040-2019, March 2019.

281 SA Power Networks, *Maximising customer value from the network in a high-DER future,* Presentation for AEMC/ARENA Regulatory DEIP dive, 6 June 2019, slides 6-8.