AEMC

REVIEW

Australian Energy Market Commission

ECONOMIC REGULATORY FRAMEWORK REVIEW

PROMOTING EFFICIENT INVESTMENT IN THE GRID OF THE FUTURE

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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.

SUMMARY

Introduction

1 The *2018 Economic regulatory framework review (2018 Review)* is the Australian Energy Market Commission's (Commission's) second annual review under a standing terms of reference from the Council of Australian Governments Energy Council (COAG Energy Council). The terms of reference request the Commission to monitor market developments in decentralised supply options as well as relevant developments in new products and services that may affect the future role of electricity distribution network service providers (distribution NSPs). Drawing on the results of this monitoring, the Commission was requested to consider whether the economic regulatory framework for electricity networks is sufficiently robust and flexible to continue to support the long term interest of consumers in a future environment of increased decentralised energy supply.

2 In this *2018 Review*, the Commission finds that incentive regulation remains the appropriate fundamental principle of the economic regulatory framework for electricity networks and that the framework currently provides sufficient flexibility to support the evolving role of NSPs in the context of the electricity sector's transformation. The Commission notes that recent changes such as the removal of limited merits review and the COAG Energy Council's decision to amend the national energy laws to make rate of return guidelines binding are designed to help to address affordability concerns.

3 Consistent with its terms of reference, the *2018 Review* has focused on considering whether changes to the economic regulatory framework are required to support likely future scenarios where there is a high penetration of distributed energy resources (DER).

4 The *2018 Review* also implements the recommendation of the *Independent Review into Future Security of the National Electricity Market* (Finkel Review) that the Commission 'undertakes financial modelling of the incentives for investments by distribution network businesses, to test if there is a preference for capital investments in network assets over operational expenditure on demand-side measures.'[1] While the Commission did not find conclusive empirical evidence that NSPs prefer capital investment (capex) over operating expenditure (opex), the financial modelling shows the the incentives between capex and opex are not aligned as they vary depending on individual circumstances. In situations where an NSP's expected cost of capital is lower than the regulated rate of return allowance, the incentives strongly favours capex. The varying circumstances faced by NSPs however mean that this cannot be addressed within the regulatory framework simply by getting the rate of return allowance 'right'.

5 The Commission therefore intends to immediately commence work as part of the *2019 Economic regulatory framework review* on changes to the expenditure assessment and remuneration provisions of the rules to develop arrangments that better align capex and

1 *Independent Review into the Future Security of the National Electricity Market: Bluprint for the Future*, p. 152

opex incentives.

6 In addition to the changes discussed above, the Commission continues to emphasise the important role that cost reflective network prices play in supporting electricity network transformation as well as delivering long term affordable energy prices. It is important to note that the economic regulatory framework does not require retailers to structure their retail prices in a way that matches the strucutre of network prices. With the roll out of advanced meters that are capable of supporting innovative pricing structures, cost reflective network prices provide cost and investment signals to third party energy services providers and retailers and enable them to develop product offerings to end consumers that would help reduce network costs in the long term. However, the move to more cost reflective network price structures is not just a network issue. It is a critical step in the efficient deployment of distributed energy resources themselves.

The grid of the future and the changing role of network service providers

7 Technological change and changing consumer preferences have transformed the landscape in which electricity network service providers operate. The role of NSPs is changing in response to this broader transformation of the sector.

8 Traditionally, the function of distribution NSPs has been to transport electricity one-way from connection points with the transmission network to consumers. Distribution network investment was mainly driven by the need to meet increasing peak demand and jurisdictional reliability standards, and most investment was traditional poles and wires capex.

9 The grid of the future is likely to perform a different function. It is expected to become a platform for a broad range of technologies and business models, managing multi-directional energy flows both to and from consumers. NSPs will face new technical and operational challenges in managing this future grid, and will need to undertake different types of investments to maintain quality and reliability and operate the network within safe limits. They will also have access to a greater range of investment options, including a likely increased ability to use opex solutions involving contracts with third party providers, for example to access distributed generation or storage services to help reduce peak demand instead of augmenting the network.

10 This change is already occurring, with the last decade seeing a significant increase in the uptake of new technologies such has rooftop solar photovoltaic systems, battery storage and ‘smart’ energy management systems at the distribution level (often collectively referred to as distributed energy resources or DER). The uptake of DER was largely consumer-driven as they respond to the financial incentives offered through Commonwealth and State schemes. Consumers could use DER to reduce their energy costs by 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.

11 These new technologies can also provide benefits to other participants within the National Electricity Market (NEM). Electricity retailers can use the energy generated and/or stored by

DER to manage their risk of participating in the wholesale energy market. NSPs can use DER to help manage the technical characteristics of their networks or reduce peak load to defer network augmentation.

12 While DER can provide a range of benefits, an increasing penetration is likely to lead to an electricity grid (especially at the distribution level) that is more complex and sophisticated. The role of NSPs will need to evolve from a simple conveyer of electricity in one direction to providing a platform to facilitate transactions between end customers, the efficient integration and operation of DER, and competitive third party energy services.

13 The increasing penetration of DER will also present challenges if not managed with more advanced technology in the distribution network. Distribution businesses, especially in South Australia and Queensland, are already experiencing technical issues caused by a high penetration of DER, and investigating a range of potential solutions to those challenges. Distribution businesses currently have very limited real-time information regarding their low voltage networks, and recognise that improved modelling and monitoring of their networks will be a key requirement to support their changing role.

The 2018 Economic regulatory framework review

Reviews and inquiries currently underway in the NEM

14 The electricity sector's transformation is not limited to distribution level changes. Significant changes are also taking place at the wholesale energy market and transmission level such as the changes to the large scale generation mix. These changes have led to stakeholder concerns about the security, reliability and affordability of electricity in the NEM. A number of reviews and inquiries are currently conducted by the Commission and other market or regulatory bodies such as the Australian Energy Regulator (AER), the Australian Energy Market Operator (AEMO) and the Australian Competition and Consumer Commission (ACCC) to address these issues:

- **Retail Electricity Pricing Inquiry (REPI).** The REPI was conducted by the ACCC under a terms of reference from the Commonwealth Treasurer to inquire into the competitiveness of the retail electricity markets within the NEM. The ACCC's final report was published on 11 July 2018.
- **Coordination of generation and transmission investment (COGATI)**. The Commission is conducting its biannual review on drivers that could impact on future transmission and generation investment. The current review is focussing on the access, connections and planning arrangements for transmission networks. A directions paper will be published in August 2018.
- **Integrated System Plan (ISP).** AEMO has prepared an inaugural ISP for the NEM. The preparation of the ISP is in response to a Finkel Review recommendation to prepare an integrated grid plan to facilitate the efficient development and connection of renewable energy zones across the NEM. The ISP was published on 17 July 2018.
- **Review of the application guidelines for regulatory investment tests (Review of RITs application guidelines).** The AER is conducting the review of RITs application

guidelines following recommendation from the COAG Energy Council's regulatory investment test for transmission (RIT-T) review in 2017. Amongst other recommendations, the RIT-T review recommended that the AER to review the application guidelines with a view to better reflect the net system benefits of options, including those relating to system security and climate goals; as well as better alignment of the regulatory investment test for distribution (RIT-D) and RIT-T in relation to the level of consultation required with non-network businesses and the requirement to produce non-network options reports under some circumstances. The AER plans to finalise the review around November 2018.

- **Review of the rate of return guideline**. The current review is the first review since the guidelines were first published in 2013. Under the current framework, the AER is to publish its second rate of return guidelines by December 2018. In October 2017, the COAG Energy Council announced that a framework for a binding rate of return guideline is to be developed. The COAG Energy Council considered that the current review, consultation and guideline development process would be taken to satisfy the process for the first binding guideline. The AER has encouraged stakeholders to approach their submissions to the review having the regard to an instrument that may be binding and that will apply in its subsequent determinations.

15 The interconnected nature of the electricity system means that no single review can adequately capture the issues that affect all aspects of the system. The terms of reference for this review direct the Commission to examine the impact on the economic regulatory framework as a result of increasing penetration of DER. This review has therefore focused on the distribution level and considered whether changes are required to the economic regulatory framework to support the continuation of the electricity sector's transformation.

Focusing on the impact of DER on the distribution system

16 Even in a future of high DER where distribution NSPs have a changing role, they will continue to play an important part in the provision of safe, secure and reliable electricity to consumers. The core regulatory obligations currently faced by distribution NSPs will continue to apply in the future. In particular, they have obligations to connect all customers that request a connection and must supply services in accordance with reliability standards set by jurisdictional governments or regulators. This means that, unlike most other business in other sectors, distribution NSPs cannot choose whether to supply customers and have limited choice over what level of service they provide to customers. This is important when considering how risks should be allocated, for example if reliability standards are set at inefficiently high levels resulting in increased network costs.

17 In this context, the Commission has assessed in this review whether the current framework for the economic regulation of distribution NSPs is expected to remain appropriate and continue to contribute to the long term interests of consumers into the future.

18 The Commission has found that the fundamental features of the economic regulatory framework remain appropriate and that an overhaul of the current regulatory arrangements is not warranted at present. The Commission considers the pace of technological change means that there are currently multiple potential variations for the future role of the grid and

the regulatory changes that may be needed to support possible future scenarios. The current focus should therefore be on actions that will support a variety of different future scenarios, rather than making regulatory changes at this stage based on a particular view of the future.

19 The Commission will work closely with AEMO and Energy Networks Australia (ENA) through the consultation on their Open Energy Networks paper to understand the technical challenges and opportunities facing networks and potential frameworks to manage system operations and optimise DER. The Commission will also work with AEMO to develop a joint work program on DER with the objective of better coordinating the various areas of work that the Commission and AEMO are currently undertaking on a range of DER-related issues.

20 In this *2018 Review*, the Commission has therefore focused its analysis on areas of the economic regulatory framework that are important to support the evolving role of NSPs and support the efficient integration of DER now and into the future. These areas are:

- Financial incentives for network service providers in light of their changing role, including an evaluation of whether the current incentive mechanisms are likely to provide balanced incentives for network investment as technological change broadens the investment options that are available to networks[2]
- Changes required to the electricity distribution system to optimise the value provided by DER and whether the current regulatory framework can support NSPs in efficiently integrating DER.
- Continuing our annual monitoring of network expenditure and performance, and considering whether additional measures are needed to incentivise efficient future network expenditure.

21 These focus areas are discussed in more detail below.

The need to review financial incentives for NSPs in light of their changing role

The incentive based regulatory approach

22 The key principle of regulation in the NEM is that it is based on incentivising NSPs to provide services as efficiently as possible. It does so by determining the maximum regulated revenues that NSPs can recover from consumers based on an estimate of the costs that an efficient and prudent NSP would incur to meet its regulatory obligations.

23 The framework also contains a number of mechanisms to incentivise NSPs to choose the most efficient solutions when providing regulated services to their customers. These incentive mechanisms can be grouped into two categories that relate to the timeframes of the regulatory period:

- **Pre-determination incentives.** The current economic regulation of NSPs in the NEM is based on the AER setting an NSP's maximum regulated revenue for a regulatory period at

2 This part includes implementing the recommendation from the Finkel review to undertake modelling to assess whether there is a bias towards capital expenditure.

the start of that period based on estimates of the costs that would be incurred by an efficient and prudent NSP. That maximum revenue is locked in at the start of the period by the AER, even if the NSP's actual costs during the regulatory period are higher than the estimated efficient costs. This provides a general incentive for NSPs to seek efficiencies during the regulatory period as they are allowed to retain the difference between their efficient costs and regulated revenues until the following period, after which those savings are passed on to consumers. This contrasts with cost of service regulation used in some other countries, where regulated revenues are based on an NSP's actual costs.

- **Post-determination incentives.** These are incentives schemes that apply to an NSP once it has received its revenue determination and include the efficiency benefit sharing scheme (EBSS), the capital expenditure efficiency scheme (CESS), the demand management incentive scheme (DMIS) and service target performance incentive scheme (STPIS). The EBSS and CESS were introduced to equalise incentives throughout the regulatory period for NSPs to seek opex and capex efficiencies, while the DMIS was introduced to provide incentives for NSPs to implement demand management initiatives. The STPIS provides incentives for distribution NSPs to deliver level of reliability that matches the value customers place on reliability.

Ongoing concerns about biased incentives

24 The incentive regulation framework and the suite of incentive mechanisms described above have been development and enhanced[3] over time to provide NSPs with improved incentives for efficient capex and opex and to seek alternatives to traditional network solutions where they are more efficient.

25 The enhancements that were made over time have retained the separate assessment and remuneration of opex and capex and many stakeholders remain concerned that NSPs have an inherent bias to prefer capital expenditure over operating expenditure. A number of submissions to the Finkel Review argued that the incentives provided to NSPs under the current framework to undertake capex is stronger than the incentives to undertake opex. This 2018 Review implements the Finkel Review recommendation that the Commission undertakes "financial modelling of the incentives for investments by distribution network businesses, to test if there is a preference for capital investments in network assets over operational expenditure on demand-side measures."[4]

26 Given the transformation of the electricity sector, the Commission's assessment of whether a capex bias exists has been undertaken against the backdrop of the evolving role of NSPs.

27 The transformation of the electricity sector and the evolving role of NSPs will require a regulatory framework that enables them to adapt to the changing environment and provides appropriate incentives for them to make the most efficient investment decision. 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

3 Schemes such as the CESS and DMIS were introduced as a result of rule changes considered by the Commission in 2012.

4 Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, p. 151.

help them manage technical issues on their networks or reduce peak demand. As a result, networks will increasingly be required to make choices whether to undertake traditional poles and wires capex investments or to use opex to procure alternative services from third parties. For example, while the traditional network solution to meet increasing consumer demand in an area would be to use capex to augment the zone substation, alternatives that are now available include using opex to purchase services from a battery provider, or an aggregator of many small-scale batteries, to reduce peak demand.

The Commission's key findings

28 The starting point of the Commission's analysis was to examine whether NSPs' past performance provide any indication of bias towards capex. This analysis was conducted using publicly available data as well as expenditure data provided by the AER as part of the monitoring aspect of this review. The Commission reviewed indicators such as capex-opex ratios, actual expenditure against regulatory allowance for the most recently completed regulatory period and NSPs' consideration of non-network solutions.

29 The Commission acknowledges that NSPs' investment decisions could be influenced by factors other than financial incentives.[5] However, it is difficult to disentangle their influence from a handful of expenditure indictors. Coupled with the changes in operating environment and the regulatory framework,[6] the Commission concludes that examination of past performance is not able to provide conclusive evidence on whether NSPs' investment decisions exhibit a bias towards capex.

30 As the examination of past performance could not provide conclusive evidence that NSPs' investment decisions is biased towards capex, the Commission considered that a modelling approach may provide insights on whether the current regulatory framework provide balanced incentives to NSPs when providing regulated services.

31 The Commission modelling approach has examined the current incentive mechanisms and their interaction with each other to determine whether the economic regulatory framework provides incentives to prefer capex over opex (or vice versa). The Commission's analysis shows that incentives for opex and capex vary depending on the circumstances:

- Where an NSP is required to implement a solution to address a change in circumstances during a regulatory periods (for example, due to a change in demand or regulatory change such as a change in reliability standards) and that requirement has a finite duration, the outcome is highly sensitive to the asset life of the capex solution chosen. An example of this situation is where in the first year of a regulatory period, an NSP is expecting an increase in peak demand for the final three years of the regulatory period that was not forecast during the regulatory determination process, but it is unclear whether that forecast increase in demand will continue indefinitely or decline again: in

5 The Commission considered other influences such as shareholders' preferences on stable returns, risk appetite as well as reputational incentives.

6 Major regulatory reforms in the last decade include the 2012 rule change on economic regulation of NSPs which provided the AER with additional flexibility when assessing regulatory proposals and introduced incentive schemes such as the CESS and DMIS. Changes in the operational environment included the significant departure of actual demand from the forecast contained in NSPs' regulatory proposals.

this scenario an NSP could chose to invest in a capex solution to expand the network to meet the increased demand or an opex solution to reduce demand and defer the potential need to expand the network until a later date. Under this situation, there is a strong capex bias for assets with short lives, and a small bias for opex instead of investing in assets with a life greater than 40 years.

- In the situation where an NSP is faced with decisions that result in an increase or decrease in expenditure and that change is assumed to continue in perpetuity, the incentives slightly favour opex regardless of asset lives.
- The above analysis assumes that the NSP's actual cost of capital is the same as the regulated cost of capital. Importantly, in either of the above scenarios, incentives are strongly biased towards capex if the NSP expects to be able to source funds at a rate lower than the regulated rate of return.

Implications of the Commission's key findings

32 The current economic regulatory framework and associated expenditure assessment and remuneration methodology were created at a time where the efficient and safe conveyance of electricity required investment in capital intensive and long-lived assets. Non-network solutions were generally not an option and there were limited opportunities for substitution between capex and opex.

33 As technology continues to evolve, NSPs are likely to have many more alternatives to traditional network solutions and an increased proportion may involve opex or assets with a much shorter life (for example battery storage).

34 Where an NSP expects to be able to source funds at a rate lower than the regulated rate of return,[7] analysis indicates that the current framework always provides a strong bias towards capex solutions, and that bias is the strongest for capex solutions that have a long expected asset life (e.g. a traditional network poles and wires solution). The Commission considers this has significant implications for the evolution of the electricity sector, especially in a future where there are a variety of solutions to a given network problem. In such a future, investment decisions that favour long-lived capital assets may lead to unnecessary network price increases, which may in turn lead to consumers making inefficient decisions on alternatives to grid-supplied energy, thus increasing the risk of asset stranding. In the near term, a strong incentive to prefer capex solutions could also hinder the development of the competitive energy services market.

35 The capex bias where an NSP's expected cost of capital is lower than the regulated cost of capital cannot be solved simply by getting the regulated rate of return "right". Given that the regulated rate of return is based on an estimate of efficient financing costs rather than actual costs, it is not possible to set a regulated rate of return that will match the expected cost of

7 As part of its rate of return guideline review, the AER sought actual debt information from NSPs to serve as 'sense check' on its current cost of debt estimation approach. The analysis was conducted by consultant Chairmont Group and showed that between 1 January 2013 and 31 December 2017, the simple 12-month rolling average of the 'cost of debt' of all new debt instruments raised by a total of 11 privately owned NSPs is lower than the estimated 'cost of debt' under the current approach. See Chapter 7 of AER's Discussion paper: estimating the allowed return on debt. The report can be found on the AER's webpage on rate of return guideline review: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-rate-of-return-guideline/initiation

capital of every NSP. It is likely that some NSPs will expect to have actual costs of capital that are materially less than the regulated rate of return and some will have actual costs that are higher.

36 It is important to note that any potential bias may not be caused by a single factor, but rather as a result of a combination of factors such as the asset life of potential solutions as well as the magnitude of the difference between an NSP's expected cost of funds compared to the regulated rate of return. In the current environment where interest rates and regulated cost of capital are low, and where the most viable solutions to many network problems may still require capital investment, the Commission's view is that the potential for bias is low and the current regulatory framework provides appropriate incentives for efficient investment decisions. However, the Australian electricity system is likely to be more decentralised in the future,[8] and DER are likely to be able to provide plausible alternatives to traditional network solutions. The Commission is concerned that the potential for bias would be greater under such a scenario, especially when combined with a high interest rate environment.

Separate operating and capital expenditure assessment and remuneration is not likely to be suitable for a future with high DER penetration

37 The issue of expenditure bias is due largely to the current method of separate assessment and remuneration opex and capex. In a future with high DER uptake and increased availability of non-network solutions using new technologies, the separate assessment and remuneration of capex and opex is not likely to lead to the most efficient outcome. The framework also creates incentives to inappropriately classifying opex as capex.[9]

38 The Commission considers that incremental changes to the current incentive mechanisms are not likely to be sufficient or appropriate to address the unbalanced incentives in the framework nor are they likely to address stakeholders' perceptions about biased incentives and cultural issues that also appear to contribute to a bias towards capital expenditure in certain circumstances.

39 Overseas regulators such as Ofwat have attempted to address similar issues in the past by using a combination of mechanism similar to the EBSS and CESS. However, Ofwat concluded that the combination of such mechanisms was not able to provide the balance required and that a system that removes the different arrangements for opex and capex was required. Advice provided to the Commission by Cambridge Economic Policy Associates (CEPA) also indicates that it is unlikely to be possible to make changes to the various current incentive mechanisms (EBSS, CESS and DMIS) so that they provide equal incentives for capex and opex in all circumstances, and that no overseas regulator has been able to achieve that outcome through changes to equivalent overseas incentive schemes.

40 The Commission's monitoring indicates that the penetration of DER is likely to continue to increase in the future. While the fundamentals of the economic regulatory framework

8 Bloomberg New Energy Finance's (BNEF's) New Energy Outlook 2018 indicates that by 2050, the Australian energy system will be one of the two most decentralized energy system in the world, with consumer PV and behind-the-meter batteries making up 44% of all capacity.

9 This is known as 'capitalisation bias'. It was one of Ofgem's main concerns when it moved to a total expenditure approach.

remains sound, the Commission considers it is appropriate to conduct a review of the method of expenditure assessment and remuneration.

41 As part of the 2019 Economic regulatory framework review, the Commission will commence consultation on changes required to the expenditure assessment and remuneration systems to enable the economic regulatory framework to continue to support the electricity sector's transformation. The Commission will commence this work immediately following the publication of this 2018 Review report.

42 A key aim of economic regulation of electrcitiy networks and other natural monopoly infrastructure is to replicate the incentives for efficient expenditure that would otherwise be driven by competition in competitive markets. However, the Commission recognises that economic regulation is always an imperfect substitute for competition and no regulatory framework can deliver perfect incentives in practice. As part of its work on these issues in the 2019 Review, the Commission will consider the materiality of the limitations in the current framework and the relative strengths and weaknesses of any alternative regulatory approaches.

The role of electricity distribution networks in optimising the value provided by DER

43 The increasing penetration of DER on the grid also presents opportunities for the power system to become more efficient as DER can be capable of providing an array of services to a range of parties. The role of NSPs will become more complex and the operation of the grid will need to be more sophisticated to efficiently integrate DER and to manage challenges to avoid network and system security issues.

Static and dynamic strategies for the management of increasing DER

44 While the future model for the efficient integration of DER is uncertain, it is useful to map out the strategies and potential changes required to move towards a more active role for distribution NSPs and distribution markets. The potential strategies fall under two categories: static and dynamic.

45 Consultations with NSPs indicate that there are static strategies that can be implemented immediately to address economic and technical issues that arise with the increasing uptake of DER. These strategies include the implementation of cost reflective network tariffs to incentivise consumers to use the network more flexibly; using network connection agreements to introduce export limits on solar PV units; and adopting power management strategies such as rebalancing low voltage phase connections and extending monitoring deeper into the low voltage network.

46 While static strategies can be implemented quickly, they have limitations. Price signals are important, but they will not prevent some technical issues arising at a network and system level due to high levels of DER export in certain parts of the network at certain times. Power quality management strategies are targeted at specific power quality issues but will also not prevent local network issues and system security issues that can arise when high levels of DER generation are exported to parts of the distribution network that were not designed for

that purpose.

47 Static export limits on export are a blunt approach to addressing the impact of distributed energy resources 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.

48 The Commission considers a more sophisticated and dynamic approach such as managing output to meet security, reliability and safety needs of the network would be better suited to managing the increasing penetration of DER. Extensive work is already being done by distribution NSPs, market bodies, market participants and technology providers on understanding the expected challenges and opportunities DER will pose for networks and system security and on potential measures to efficiently integrate DER to the grid, including more active and dynamic options.

Potential models for the optimisation of DER

49 The Commission requested, as part of its findings in its Distribution Market Model report that Energy Networks Australia (ENA), in consultation with relevant stakeholders, start to explore what minimum level of control distribution NSPs need to have over DER in order to enable higher levels of DER for future distribution level markets, without compromising their regulatory obligations including reliability and quality standards.

50 In line with this recommendation, and as part of their broader work in this area, the ENA and AEMO published a joint consultation paper Open Energy Networks on 15 June 2018 to explore potential active and dynamic approaches to integrating DER in the NEM to optimise the value of DER while managing distribution network constraints and system security. The consultation paper sets out several "straw man" frameworks for a distribution system operator (DSO) or distribution level optimisation to be developed further with stakeholders. It also discusses the high level functions, roles and responsibilities required to coordinate DER optimisation within both transmission and distribution network limits and the different options proposed by the ENA and AEMO for allocating the responsibility to manage DER optimisation and dispatch.

51 Developing a framework for managing and optimising DER dispatch will require further development and consultation. Implementation would also require considerable time. The Commission will continue to work with the ENA, AEMO and other stakeholders on the evolving role of distribution networks, including potential models for the optimisation of distribution-level markets.

Initial steps that should be taken now to provide the foundation for the future

52 The identification of the preferred approach to overall system operation and the assessment of benefits of alternative models is likely to take considerable work and time. In the meantime, there are a number of first steps that distribution NSPs can take now to facilitate the integration of DER and to prepare for potential future operating models.

53 The key first steps involve distribution NSPs building a better understanding the impacts of

connecting higher levels of DER to their networks and the network constraints that may emerge as a result. In the past, distribution networks have not needed a detailed understanding of flows of energy across their low voltage networks, with most of their modelling and monitoring capability focussed on their high voltage networks. As a result, they have very limited information regarding the ability of their low voltage networks to manage DER export and the constraints in their networks that will lead to high levels of DER causing them to breach their technical obligations in relation to matters such as voltage limits.

54 The Commission considers the current economic regulatory framework can support distribution NSPs in making efficient investments to improve their low voltage network data, modelling and monitoring capacity as it provides distribution businesses and the AER with appropriate levels of discretion and flexibility in determining network expenditure and revenue requirements.

Annual monitoring of network service providers' expenditure and performance

55 As part of the review, the Commission monitors on an annual basis key performance indicators for NSPs. The results of the monitoring form part of the Commission's assessment of whether NSPs are responding to changes in the market and whether changes to the regulatory framework are required. This year's monitoring update is limited to metrics of investment in network infrastructure as well as some operational metrics, with a focus on distribution NSPs.

56 A key trend that is of note is the slowdown in the growth of the regulatory asset base (RAB) in recent years. Over the last three years, the combined distribution NSPs' RAB has been flat at approximately $70 billion.

57 One of the major factors impacting the RAB is the level of capex in the network. Since 2011-12, there has been a sharp decline in the level of distribution NSP capex. In real terms, the combined distribution NSP capex in 2016-17 is lower than the level in 2005-06.

58 While this issue appears to be largely historical, there is a risk that the current trend of flat RABs may change and we may experience another period in the future of large growth in capex and RABs.

59 Under the current framework, when deciding the RAB roll-forward for a NSP at the start of a regulatory period, the AER has the ability to review the efficiency of NSP's capex during the previous regulatory period only if the total capex over the previous regulatory period exceeded the capex allowance set by the AER in its determination for that period. Under this limited power, the AER also only has the ability to review the amount of the overspend above the allowance and it cannot reduce the amount of capex that is rolled into the RAB to an amount that is below the level of the allowance set by the AER in its determination for that period.

60 For the *2019 Economic regulatory framework review*, the Commission will consult with stakeholders on whether extending the AER's ability to conduct ex-post capital expenditure

reviews to all capital expenditure from the previous regulatory period would be an appropriate tool to manage future risks of over-investment by NSPs.

The need to continue network pricing reform

Why cost reflective network tariffs are important

61 While the reforms discussed above are important in facilitating network transformation and promoting more efficient investments in network infrastructure, network tariffs reform continues to play an important role.

62 Cost reflective network pricing will support the transformation of the network by providing a foundation for efficient usage and investment decisions by consumers. In particular, network tariff reform will provide investment signals to DER providers and help unlock the DER value stack by assisting consumers to optimise their energy usage. This is forecast to lead to long-term reductions in network costs and average network charges paid by consumers.

63 The Commission considers that it is not necessary for retailers to structure their prices in a way that matches network prices. Network prices are not paid directly by customers, and are instead charged by distribution NSPs to retailers. If network prices are cost reflective, this will incentivise retailers and other energy service providers to offer innovative solutions to help consumers manage their demand and costs. Retailers will also play an important role in removing complexity for consumers, just as they currently do in managing a wholesale price that varies every 30 minutes and packaging that into a retail price that is simpler for consumers to understand and respond to.

The progress of reform

64 The requirement for NSPs to develop cost reflective network prices was introduced by the Commission's *Distribution network pricing arrangement* rule change in 2014. The rule change also requires NSPs to develop a tariff structure statement (TSS) that outlines the price structures that they will apply for the next regulatory period. In doing so, distribution NSPs must develop tariffs that comply with principles set out in the rules, including a consumer impacts principle that requires distribution NSPs to manage the impacts of network price changes on consumers.

65 The first TSS period, which was an interim period from 2017-18 to 2019-20, has seen distribution NSPs gradually shift their tariff structures from consumption-based and declining block tariffs (where electricity consumption becomes cheaper as it increases) in favour of time of use (TOU) tariffs and demand tariffs. TOU tariffs have lower charges for consumption during times when demand on the network is lower. Demand tariffs involve a demand charge based on either the customer's maximum demand at any time of the day or the customer's maximum demand during a specified time period when the network usually experiences peak demand. Under either tariff structure, the regulatory framework prevents distribution NSPs increasing the total amount of revenue they recover from consumers, so any increase in one part of the tariff is offset by a reduction in other parts of the tariff. These new tariffs are primarily for customers with remotely-read interval meters, which are progressively being

rolled out across the NEM under the Commission's competition in metering rule change, with the exception of Victoria where the roll-out was completed in 2015.

66 Cost reflective network tariffs in the first TSS period were generally offered on an 'opt-in' basis, which has led to a slow uptake of cost reflective tariffs so far. The Commission notes that for the upcoming TSS period, many NSPs have started to shift to 'opt-out' or mandatory assignment policies. The Commission notes this is a positive development and encourages market participants, governments, consumer groups and the AER to continue to progress implementation of network tariff reforms through the current TSS processes for the regulatory periods commencing from July 2019.

Areas of focus for future reviews

67 As the role of NSPs continues to evolve in response to the electricity sector's transformation, other reforms may be needed so that the economic regulatory framework continues to serve the long term interest of electricity consumers.

68 Additional issues that have been raised by stakeholders that the Commission intends to consider in the *2019 Economic regulatory framework review* include:

- Enhanced consumer engagement, in particular any changes as a result of the NewReg project currently being undertaken by the AER, ENA, and Energy Consumers Australia
- Increased use of output or performance based regulation
- Potential changes to how risks are shared between NSPs and consumers, including consideration of extending the AER's power to conduct ex-post reviews of the efficiency of capital expenditure incurred in the previous regulatory period
- Whether there is need for more formal arrangements for regulatory sandboxes to enable innovation.

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1 BACKGROUND

1.1 About this review

The annual review of the economic regulatory framework for electricity networks is part of the Australian Energy Market Commission's work to support the ongoing evolution of the energy sector. In light of the significant growth in distributed energy resources (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.

This report is prepared under the standing terms of reference provided by the Council of Australian Governments (COAG) Energy Council.[10] The tasking arose from COAG Energy Council's concerns that the economic regulatory framework may not support the delivery of the national electricity objective (NEO) in light of the changes in the energy market, particularly with the increasing penetration of distributed energy resources (DER). The Commission is required to publish a report by 30 June annually.

The first report of this review was published in 2017.

1.2 The 2018 Review

Technological change has transformed the landscape in which network service providers (NSPs) operate. Rooftop solar photovoltaic systems (PV), battery storage and 'smart' energy management systems at the distribution level (referred to as distributed energy resources, or DER in this report) are providing consumers with more ability to manage their energy needs. These new technologies are providing benefits not only to consumers, but also to other participants within the National Electricity Market (NEM). In particular, new technologies are increasingly providing credible alternatives to traditional poles and wires solutions to network issues, particularly in the distribution system.

The grid of the future is likely to have an increasing amount of DER. This is likely to require network service providers to play a greater role in facilitating and efficiently integrating DER so that the multiple value streams of DER are unlocked to deliver more affordable electricity to consumers. The increasing penetration of DER will also present challenges if not managed with more advanced technology in the distribution network. Distribution NSPs in South Australia and Queensland are already experiencing technical issues caused by a high penetration of DER, and are working on potential solutions to those challenges.

The changing operating environment may require the role of NSPs to become more complex, and a number of approaches could be taken to manage the integration of an increasing level of DER. However, even in a future of high DER, NSPs will continue to play an important role in the provision of safe, secure and reliable electricity to consumers.

In this context, the Commission's analysis is that the fundamental features of the economic regulatory framework remain appropriate in the foreseeable future and an overhaul of the

10 The terms of reference can be found at: https://www.aemc.gov.au/sites/default/files/content/c2a5ac6f-823d-4cf3-8a7f-50545ae25667/EPR0050-Economic-Regulatory-Framework-Review-Final-Terms-of-Reference.PDF

current regulatory arrangements is premature. The Commission considers that a clearer view of the future operating arrangements of the grid needs to be developed before a view can be reached on whether any broader changes to the regulatory framework are needed.

In this *2018 Economic regulatory framework review* (2018 Review), the Commission has therefore focused its analysis on areas of the economic regulatory framework that are important to support the evolving role of NSPs and support the efficient integration of DER now and into the future. These areas are:

- **Financial incentives for NSPs in providing economically regulated services:** This part of the review reports on the outcome of analysis and modelling on whether there is a bias in the incentive framework that results in NSPs favouring capital expenditure (capex) over operating expenditure (opex). The outcome of the analysis has informed the Commission's consideration on whether changes is required to the current expenditure assessment and remuneration framework under the national electricity rules (NER).[11]
- **Continuing the development of competitive distribution markets:** This part of the review builds on some of the findings of the Commission's *Distribution Market Model*[12] (DMM) project by considering the possible changes required to the electricity distribution system to move towards a distribution level market framework. The report also considers whether the current regulatory framework can support NSPs in efficiently integrating the DER.
- **Monitoring of key market trends and NSPs' expenditure and performance:** The standing terms of reference require the review to undertake annual monitoring of electricity network issues. This year's monitoring work outlines the observed recent trends in NSPs' expenditure and performance.

1.2.1 Assessment framework

The Commission is guided by the NEO when considering the effectiveness of the current economic regulatory framework in light of the increasing uptake of DER. The NEO is set out in section 7 if the National Electricity law (NEL) and states:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

As discussed throughout this report, the changing energy system and high uptake of DER raises a number of technical and regulatory opportunities and challenges.

The Commission's analysis is also informed by the following principles:

11 This part of the review also delivers on a Finkel Review recommendation by providing an assessment of the incentives network businesses face when providing regulated services.

12 *AEMC, Distribution Market Model Final Report, August 2017.*

- **Clarity:** It is important to have a clear vision for the role of distribution NSPs in the new energy system and clearly articulate a desired set of outcomes distribution NSPs are expected to deliver to customers. NSPs need to understand what is expected of them and have clear incentives to meet these expectations. If incentives are too complex and difficult to assess trade-offs between them, they will fail to have the desired outcomes for customers. The Australian Energy Regulator (AER) also requires clarity in the regulatory framework on the objectives and criteria it is to apply when assessing NSPs' regulatory proposals, while retaining appropriate flexibility as to how to assess those proposals.
- **Flexibility:** It should not be the role of the regulatory framework to determine exactly what electricity networks look like in the future. Given rapid developments in technology, the regulatory framework needs to provide flexibility to the AER and distribution NSPs in how they deliver the desired outcomes at the lowest possible cost for customers. For example, NSPs should have the flexibility to incorporate new technologies and non-network solutions as they become increasingly available.
- **Consumer involvement:** Consumers will need to continue to be involved in setting the expectations of NSPs and informing the role of networks. Consumers will know their preferences better than policy makers and regulators. The regulatory framework should facilitate the AER, NSPs and consumers to build understanding and trust in order that the services that consumers value can be delivered at a price they are willing to pay.

1.2.2 Approach taken by the Commission

As part of the review process the Commission consulted with a variety of stakeholders. The stakeholders included distribution NSPs, transmission NSPs, market bodies including the Australian Energy Regulator (AER) and Australian Energy Market Operator (AEMO), Energy Consumers Australia (ECA) and other consumer representative bodies as well as industry bodies such as Energy Networks Australia (ENA).

In developing the market monitoring sections of the review, the Commission engaged extensively with the AER. The data used for the market monitoring sections was provided by the AER.

The Commission received one informal submission for the review from ElectraNet. This is published on the review's website.[13]

1.3 Structure of this report

This report is structured as follows:

- Chapter 1. The remaining part of this chapter will provide a summary of the Commission's monitoring of market trends, a brief description of the current incentive regulation framework and definition of key terms used throughout this report.
- Chapter 2 reports on the outcome of analysis and modelling on whether there is a bias in the incentive framework that results in NSPs favouring capex over opex. This chapter also

13 https://www.aemc.gov.au/sites/default/files/2018-05/ElectraNet.pdf

contains the Commission's recommendations on whether changes are required to the current expenditure assessment and remuneration framework.

- Chapter 3 discusses the Commission's annual monitoring of some of the key performance indicators for NSPs.
- Chapter 4 outlines the opportunities and challenges created by high levels of DER uptake by consumers.
- Chapter 5 provides an overview of the key anticipated changes in the way distribution networks will need to be managed in response the uptake of DER.
- Chapter 6 discusses how the current economic regulatory framework can facilitate network transformation and development of distribution markets.
- Chapter 7 outlines the areas of focus for the *2019 Review*.

1.4 Market trends – consumer choices driving changes at the distribution level

It is well established that the electricity industry in Australia is undergoing fundamental changes, with the market trends impacting the industry expected to drive significant changes to electricity networks. This year's monitoring of key market trends explores the increased consumer engagement at the distribution level with the uptake of DER.

Consumers are becoming increasingly engaged with the energy market through the uptake of new technologies and services, such as solar PV, battery storage and energy management products and services. They are increasingly demanding more control over their energy decisions and are interested in a range of innovative products that are becoming more available, due to changing technology and reducing costs.

This section provides an update on trends in consumer investment in these DER, the drivers of this investment and the trends expected into the future.

1.4.1 High levels of distributed solar PV generation

The Australian energy market has seen a strong uptake of small scale solar PV by consumers over last decade. As a result, Australian jurisdictions now have some of the highest proportion of households with solar PV in the world.[14]

Figure 1.1 below shows the investment in small-scale solar PV that has taken place in NEM states over the last eight years. During this period, the NEM regions saw a combined uptake of more than 5.5 GW of small-scale solar PV.[15] As of May 2018, the magnitude of the installed small-scale PV capacity in the NEM regions was 5.8 GW, which is approximately equivalent to 12% of the total generation capacity in the NEM.[16] As reported in the Commission's *2018*

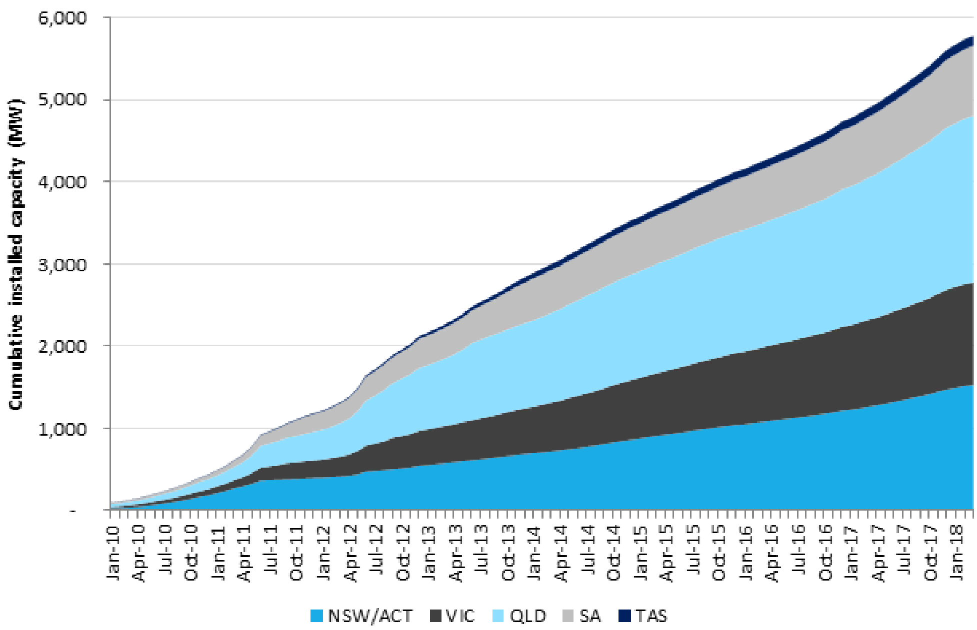
14 Australian Energy Council, *Renewable energy in Australia-How do we really compare*, June 2016, p.4.

15 Includes all installations below the 100 kW capacity.

16 Calculated using the Australian Photovoltaic Institute PV postcode data and data from the AEMO generation information page. The calculation includes PV systems below the size of 100 kW and the registered scheduled and non-scheduled generation capacity in the NEM.

retail competition review, 2017 saw a 25% increase in PV installation over the previous year, adding an additional 938 MW capacity across the NEM regions in one year.[17] Most of this capacity installation has taken place behind the meter on residential properties.

Figure 1.1: Installed small-scale Solar PV capacity in the NEM regions



Source: AEMC adaptation of postcode data from the Australian PV institute[18]

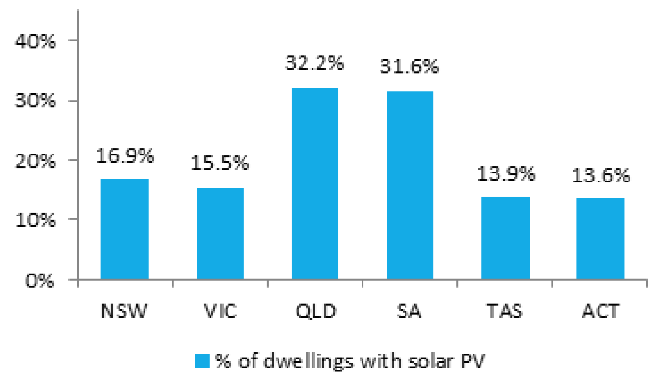
Figure 1.2 below shows the proportion of dwellings with solar PV systems in each of the NEM jurisdictions. A significant proportion of households in the NEM regions have rooftop PV, with almost one in three dwellings in Queensland and South Australia having installed rooftop solar PV.[19]

17 AEMC, 2018 *Retail competition review*, June 2018, p.140.

18 Australian Photovoltaic Institute, viewed: 3 May 2018, http://pv- map.apvi.org.au/postcode. Note: only systems below 100 kW were included in the analysis

19 As 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.

Figure 1.2: Share of households with solar PV in the NEM



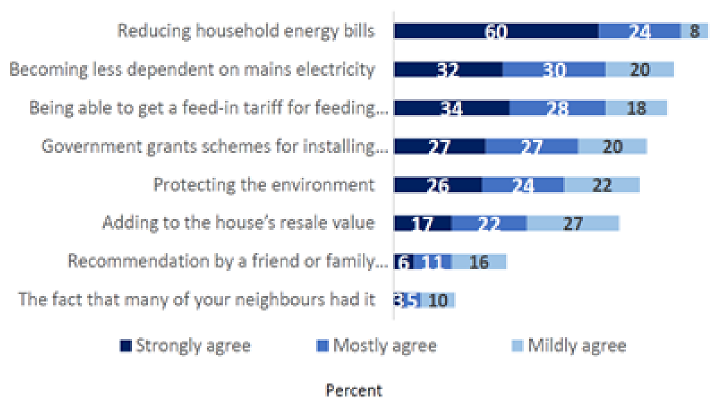
Source: AEMC adaptation of Mapping Australian Photovoltaic installations data from Australian PV institute[20]

Almost all of the distributed solar PV installations to date are 'passive' systems that are limited in their ability to respond to market signals. They were generally installed for the purposes of self-consumption or passive exports to the grid.

Drivers of solar PV uptake

There are several motivating factors behind the consumer uptake of rooftop solar PV and these have been the subject of several studies. The key drivers of the rooftop PV reported by a study commissioned by Energy Consumers Australia (ECA) are shown in Figure 1.3 below.

Figure 1.3: Drivers of rooftop PV uptake



Source: ECA and UMR strategic research *Usage of solar electricity in the national energy market*.

20 Australian Photovoltaic Institute 2018, viewed: 3 May 2018, http://pv- map.apvi.org.au/historical#4/-26.67/134.12

The study indicated that cost saving financial factors were the main drivers of electricity consumer uptake of solar PV, with 92% of the surveyed consumers indicating that they were motivated by the prospect of reducing their bills.[21] Other financial factors including the feed-in tariffs and government grant schemes such as the Commonwealth government's (Small-scale Renewable Energy Scheme) SRES scheme were also key motivating factors for consumers. Longer term factors such as becoming less dependent on the mains electricity, protecting the environment and adding to the value of the house were also major factors, with reputational factors also contributing to consumers' decision to install solar PV.

The significant uptake of rooftop solar in recent years has coincided with increases in retail electricity prices in the NEM and the continuation of decreases in solar PV system costs, which adds to the value proposition of installing rooftop PV.[22]

1.4.2 Increasing uptake of battery storage

The energy market is starting to see an uptake of battery storage systems by consumers. Battery storage allows consumers to store excess generation from their PV systems or lower priced electricity from the grid for use at a later time or when grid electricity is expensive, in order to reduce their overall cost of electricity consumption.[23] In comparison to solar PV technologies, home and grid scale battery storage technologies are less mature. Battery storage is an emerging market and currently there is a range of battery storage products available to consumers that use different technologies and have different characteristics.[24]

Currently there is limited availability of reliable data on uptake of battery storage in the NEM. The Clean Energy Regulator (CER) has a record of some of the combined battery and solar PV installations, which has been provided by consumers on a voluntary basis. Figure 1.4 below shows the number of combined PV - battery systems being installed in the NEM every year.[25] The CER dataset shows that although there is not a large number of battery systems installed to date, there is a trend of acceleration in the adoption of household battery storage with PV systems in the NEM states. The dataset had recorded approximately 7,000 combined solar PV battery system installations in the NEM states by March 2018. In relation to the collection and sharing of information about DER in the NEM, the Commission is currently considering a rule change to establish a national register of DER, including small-scale battery storage systems and rooftop solar.

21 UMR Strategic research, *Usage of solar electricity in the national electricity market*, November 2016, p.12.

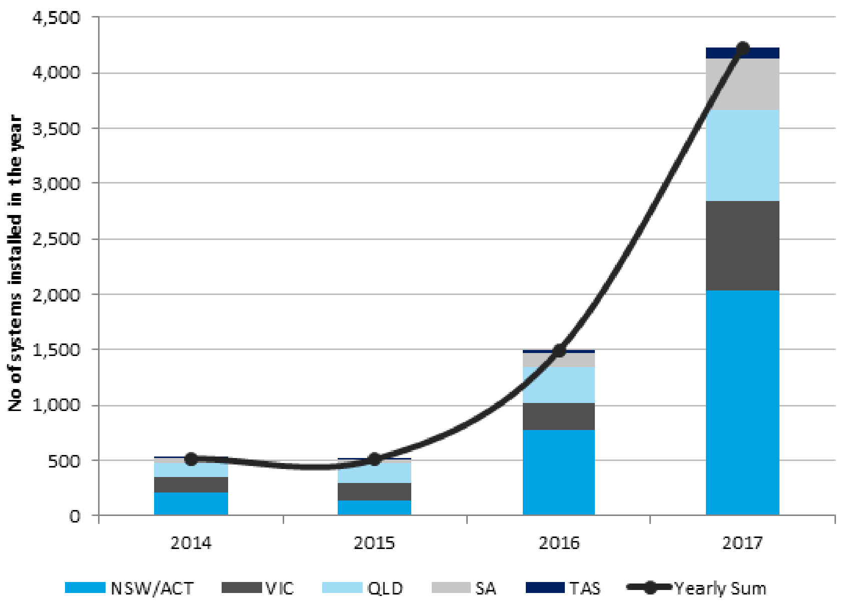
22 AEMC, 2018 *Retail competition review*, June 2018, p.138.

23 AEMC, 2018 *Retail competition review*, June 2018, p.141.

24 Example technologies include lithium-ion, lead-acid and flow batteries.

25 It should be noted that this data is provided to the CER on a voluntary basis and is expected to represent a subset of total battery storage installations.

Figure 1.4: Combined battery storage and PV system installation reported to CER



Source: AEMC adaptation of data from Clean Energy Regulator - Solar PV systems with concurrent battery storage capacity by year and state/territory[26]

Other sources, such as Sunwiz have reported the cumulative uptake of battery storage in Australia to be approximately 28,000 systems. According to Sunwiz, more than 20,000 home energy storage installations took place in 2017 with 12% of solar installations in 2017 including batteries.[27]

1.4.3 Demand management uptake

The market is also seeing an emergence of products and services aimed at helping consumers manage their power consumption, and the performance of their other DER. Although some of these products are developed to provide consumers with lifestyle and convenience benefits, other products can help consumers manage their usage and participate in wholesale and network demand management. Examples of such products include Zen Thermostats, Watt-watchers and Redback technologies' smart hybrid system. The emergence of such products, their reducing costs and the increasing penetrations of enabling technology, such as advanced metering is making it easier for consumers to participate in demand management.

26 Clean Energy Regulator 2018, Clean Energy Regulator Canberra, viewed 3 May 2018, http://www.cleanenergyregulator.gov.au/RET/Forms-and- resources/Postcode-data-for-small- scale-installations.

27 Sunwiz 2018, viewed 4 May 2018, http://www.sunwiz.com.au/index.php/2012-06-26-00-47-40/73-newsletter/434-australian-battery- market-trebles-in-2018.html

By having consumers change their demand in response to signals, they are able to provide a number of services. Types of demand management can be defined by the service it is intended to provide. The different types of demand management services include:[28]

- Ancillary services demand response
- Network demand response
- Wholesale demand response
- Emergency demand response.

There are currently several demand management programs being undertaken by retailers and distribution NSPs. The programs vary in terms of how they achieve a reduction in demand and the segments of the market they target. Examples of some of these programs include:

- Powershop's 'curb your power' program that urges customers to reduce their energy consumption through SMS notifications[29]
- United Energy's 'Dynamic Voltage Management System' that involves reducing voltages across many of its substations by a small amount to reduce peak demand.[30]

1.4.4 Expected DER uptake into the future

The uptake of DER and their enabling technologies is expected to continue into the future, as consumers continue to seek ways to better manage their energy use and make the most of the products and technologies coming on to the market. As a result, an increasing level of DER is expected to enter the market. This expected uptake is driven by a range of factors including:[31]

- the falling costs of DER technologies
- increasing functionality of these technologies[32]
- more sophisticated information and control technologies, and fast, cheap computing platforms
- changing consumer attitudes to electricity supply and prices

Figure 1.5 below shows the AEMO's forecast uptake of small-scale PV and battery system capacity in the NEM.

28 AEMC, *Interim Report: Reliability Frameworks Review*, p.54, December 2017.

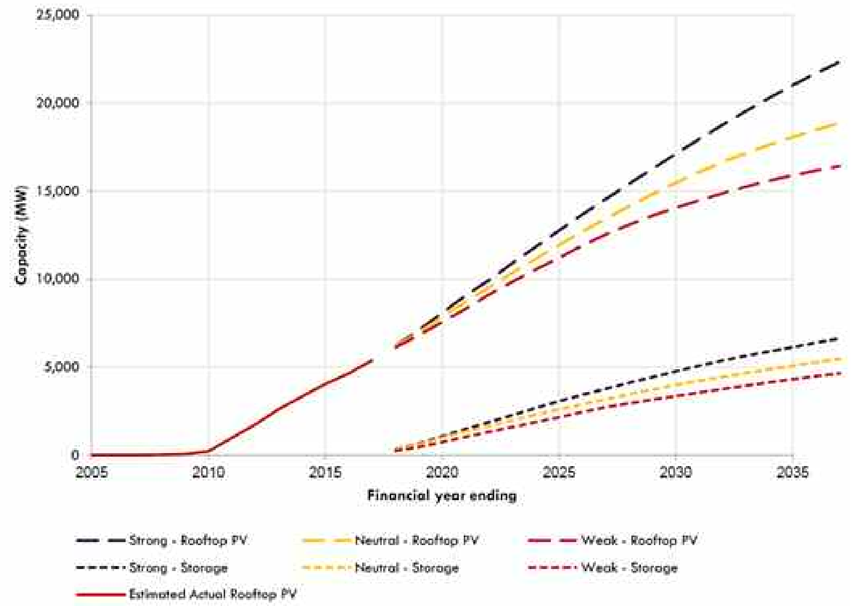
29 Powershop, viewed 16 April 2018, https://www.powershop.com.au/demand-response-curb-your-power/

30 ARENA 2017, ARENA Canberra, viewed 20 April 2018, https://arena.gov.au/blog/demand-response-4/

31 AEMC, *Distribution Market Model Final Report*, August 2017, p.10.

32 For example, the Tesla Powerwall 2 has double the storage capacity, at close to half the price, compared to the Tesla Powerwall 1, with these two models being released less than two years apart. See: http://www.cleanenergyreviews.info/blog/tesla-powerwall-2-solar-battery-review

Figure 1.5: AEMO forecast trends in DER uptake



Source: AEMO observations: Operational and market challenges to reliability and security in the NEM.[33]

AEMO's forecast for rooftop PV and battery storage uptake as reported in *the 2017 Electricity forecasting insights* expects the total small-scale PV capacity and battery storage capacity to reach 19.7 GW and 5.6 GW respectively by 2037.[34]

AEMO expects the growth in installed PV to remain high initially but the growth rate is forecast to slow, with Commonwealth government incentives progressively being phased out, and the level of installations reaching saturation point due to availability of suitable roof space. The expected growth rates are expected to be particularly high for commercial PV systems, and PV systems combined with battery storage.[35]

There are some differences in the projections of DER uptake from different stakeholders. For example Bloomberg New Energy Finance (BNEF) expects a surge of PV uptake by industrial consumers.[36]

Emerging technological trends such as electric vehicles are also expected to have an increasing impact on the energy market. AEMO expects the uptake of electric vehicles to result in 14,500 GWh of annual energy consumption across the NEM by 2036-37.[37]

33 AEMO, *AEMO Observations: Operational and market challenges to reliability and security in the NEM*, March 2018, p.22.

34 AEMO, *Electricity Forecasting Insights 2017: Rooftop PV and Battery Storage*, viewed 23 May 2018, https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and- forecasting/Electricity-Forecasting-Insights/2017-Electricity-Forecasting-Insights/Key-component- consumption-forecasts/PV-and-storage.

35 Ibid.

36 BNEF, *Australia behind-the-meter pv and storage forecast,* February 2017.

37 AEMO, *Electricity forecasting insights: Assumption Changes*, viewed 16 May 2018, https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/2018-Electricity-Forecasting-Insights/Assumption-Changes

The changes to the electricity system are not limited to distribution level changes. There are significant changes also taking place at the transmission level such as the changes to the large scale generation mix. The Commission has put in place measures to address the emerging challenges associated with the changing large scale generation mix. Appendix 1 provides further details.

As highlighted by this section, there has been a significant uptake of DER by the consumers. The uptake of DER and their enabling technologies is expected to continue into the future resulting in increasing levels of DER penetration for the distribution networks. As the Commission sets out later in this report, measures such as network tariffs can play a role in setting the appropriate incentives for efficient investment in DER.

Considering the evolving role of NSPs in a high DER future, an understanding of the opportunities and challenges posed by DER will be necessary. These issues, including the role network tariffs play in providing a signal for efficient DER investment and the role of the economic regulatory framework in supporting the electricity sector transformation are explored in later chapters of this report.

1.5 The incentive regulation framework

The key principle of network regulation in the NEM is that it is based on incentivising NSPs to provide services as efficiently as possible. It does so by determining the maximum regulated revenues that NSPs can recover from consumers based on an estimate of the costs that an efficient and prudent NSP would incur to meet its regulatory obligations. The framework does not allow NSPs to necessarily recover their actual costs, with the most they can recover being this maximum revenue amount that is based on an assessment of efficient costs.

The AER locks in NSPs' maximum allowed revenues prior to each regulatory period. With revenue locked in and based on efficient costs, NSPs are incentivised to provide required services at the lowest possible cost.[38] If NSPs reduce their costs to below the AER's estimate of efficient costs, the savings are shared with consumers in future regulatory periods. This approach is in contrast to the cost of service approach used in some other countries where NSPs are allowed to recover the actual costs they incur.

It is also important to note that the current regulatory framework does not provide NSPs with a 'guaranteed' rate of return. Under the incentive regulation framework, NSPs will bear some risks. For example, an NSP would not receive additional revenue during a regulatory period if its expenditure is higher than the forecast efficient expenditure at the beginning of the regulatory period.[39] As with the assessment of efficient costs, the regulated rate of return is not based on an NSP's actual financing costs and is instead based on the efficient financing costs of a benchmark efficient entity with a similar degree of risk as the NSP.[40] The NSP bears

38 The reliability standards are set by state jurisdictional requirements.

39 The NER contains provisions to allow certain limited types of unforeseen costs increases (or decreases) to be passed through to customers, subject to a materiality threshold, for example costs caused by a law change during the regulatory period.

40 The COAG Energy Council is proposing changes to the way the rate of return is set. See: National Electricity Law And National Gas Law Amendment Package – Creating a binding rate of return instrument.

the risk that its actual financing costs may be higher, and it cannot pass those higher costs on to consumers.

Another key feature of the electricity network regulatory framework that is important when considering the degree of risk that should be borne by NSPs is the nature of the regulatory obligations they face. In particular, NSPs have obligations to connect all customers that request a connection and must supply services in accordance with reliability standards set by jurisdictional governments or regulators. This means that, unlike most other businesses in other sectors, NSPs cannot choose whether to supply customers and have limited choice over what level of service they provide to customers. This is important when considering how risks should be allocated, for example if reliability standards are set at inefficiently high levels resulting in increased network costs.

1.6 Key terms

Table 1.1: The Commission's definitions of the key terms used in this report.

TERM OR ABBREVIATION	DEFINITION
Active DER	DER capable of responding automatically to short-term changes in prices or signals from wholesale markets or elsewhere in the supply chain.
DER (Distributed Energy Resources)	An integrated system of energy equipment that is connected to the distribution network, including both 'active' and 'passive' devices, for example solar PV and other forms of distribution-connected generation, batteries, load control and home energy management systems.
Distribution-level markets	Markets for the provision of electricity services in distribution networks, for example the competitive procurement of services enabled by distributed energy resources for the purposes of managing network congestion.[41]
Optimisation of DER	To make efficient decisions about investment in and operation of a distributed energy resource, given any technical constraints that

41 We use the term 'competitive procurement' here in the economic sense – that is, the buying and selling of services enabled by distributed energy resources by competing businesses in response to market-based signals, not the DNSP's provision of the common distribution service, which could include the procurement of network services from distributed energy resources.

TERM OR ABBREVIATION	DEFINITION
	leads to minimisation of total system costs.
Passive DER	DER not capable of responding automatically to short-term changes in prices or signals from wholesale markets or elsewhere in the supply chain, eg rooftop solar PV that generates and feeds power into the grid when the sun shines but cannot adjust its output in response to short term changes in market signals.[42]

42 We envisage that 'passive' devices may become 'active' as the minimum technical requirements of such systems are updated over time, and, if the incentives to do so exist and the cost of doing so is not prohibitive.

2 INCENTIVES FACING NETWORK SERVICE PROVIDERS – IS THERE A BIAS?

In the past decade, new technologies have changed the operating landscape for network service providers (NSPs). One of the most significant changes is the shift from centralised generation to more distributed energy resources (DER). This change means that the electricity network has evolved from a system that transports electricity in one direction from large centralised power stations to one that needs to support DER and multi-directional electricity flows. However, this does not alter the the primary function of NSPs, which is to provide safe, secure and reliable supply of electricity to end consumers. As the uptake of DER continues to increase, in order to efficiently meet their obligations to provide safe, secure and reliable regulated network services, NSPs' role in the future may evolve to take on additional functions such as acting as a platform to facilitate the efficient integration of DER and supporting third party providers in their provision of energy management services to customers.[43]

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. In the future, NSPs are increasingly likely to be required to make choices whether to undertake traditional poles and wires capital expenditure (capex) investments or to use operating expenditure (opex) to procure alternative services from third parties. For example, while the traditional network solution to meet increasing consumer demand in an area would be to use capex to augment the zone substation, alternatives that are now available include using opex to purchase services from a battery provider, or an aggregator of many small-scale batteries, to reduce peak demand.

It is clear that NSPs' role needs to evolve in the future to adapt to changes in the electricity sector, but the exact scope of that future role is unclear at this stage. It is therefore important that the regulatory framework provides sufficient flexibility to enable them to adapt to the changing environment and provides appropriate incentives for them to make the most efficient investment decisions.

In this chapter, the Commission examines whether financial incentives under the current regulatory framework will remain suitable in a high DER future to enable NSPs to make efficient investment decisions when faced with the choices described above. This chapter also discusses the Commission's analysis on whether a capex bias exists under the current regulatory framework as recommended in the *Independent Review into the Future of the National Electricity Market: Blueprint for the Future*(the Finkel Review).[44]

43 It is important to note that the function of providing a platform to support third party service providers and facilitating the integration of DER is different from an NSP being an active participant in providing contestable energy services. Consistent with the previous views, the Commission considers that NSPs, as monopoly service providers, should not participate in contestable markets unless it is through an appropriately ring-fenced entity.

44 *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, p. 151.

Commission's key findings

- Incentives for capex and opex vary depending on circumstances
  - Where an NSP is required to implement a solution to address a change in circumstances during a regulatory period (for example, due to a change in demand or regulatory change such as a change in reliability standards) and that requirement has a finite duration, the outcome is highly sensitive to the asset life of the capex solution chosen but the incentives generally favour capex. [45]
  - In situations where an NSP is faced with decisions that result in an increase or decrease in expenditure and that change is assumed to continue in perpetuity, the incentives slightly favour opex regardless of asset lives.
  - The above analysis assumes that the NSP's actual cost of capital is the same as the regulated cost of capital. In either of the above scenarios, incentives are strongly biased towards capex if the NSP expects to be able to source funds at a rate lower than the regulated rate of return.
- Despite recent regulatory reforms, the perception that the current framework provides biased incentives for capex still holds
  - Despite the introduction of recent reforms such as the capital expenditure efficiency scheme (CESS), demand management incentive schemes (DMIS) and limited ex-post review of capes to strengthen incentives for NSPs to seek alternatives to traditional network solutions, there remains a strong perception that the current framework provides biased incentives for NSPs to prefer capex over opex.
  - This perception is raised by many stakeholders (including NSPs) during consultations for this review and other recent Commission projects.
  - Research conducted by Cambridge Economic Policy Associates (CEPA) for this review also cites investment analysts' views that 'RAB growth is a generally desirable outcome in investors' consideration of regulated businesses'. While this will vary amongst NSPs depending on matters such as the nature of their shareholders, there is a risk that cultural and reputational factors could contribute to a capex bias for some NSPs
- Separate opex and capex expenditure assessment and remuneration is not likely to be suitable for a future with high DER penetration
  - Separate opex and capex expenditure assessment and remuneration may not be the most appropriate approach in the future given the predicted growth in non-traditional solutions.
- Incremental changes to current incentive schemes are not likely to be sufficient
  - The incentive mechanisms under the current framework have become quite complex and their combined effect depends heavily on assumptions and individual circumstances. As the variety of solutions to network problems increase, this complexity is likely to cause unintended outcomes where NSPs may respond to incentives incorrectly.

- Incremental changes to the current incentive mechanisms are not likely to be sufficient or appropriate to address the biased incentives in the framework nor are they likely to address stakeholders concerns or perceptions about biased incentives.

Commission's recommendation

As part of the 2019 economic regulatory framework review, the Commission will commence consultation on changes required to the expenditure assessment and remuneration systems to enable the economic regulatory framework to continue to support the electricity sector's transformation. The Commission will commence this work immediately following the publication of the 2018 Review report.

2.1 Introduction

The economic regulation of NSPs is based on the building block methodology and incentives are provided to NSPs to reduce costs, improve service quality and undertake efficient investment.[46] An element of the current framework is the separate assessment and method of recovery of capital and operating expenditure.

The issue of NSPs preferring capex over opex under the current framework has been the subject of reviews and regulatory changes both in Australian and overseas jurisdictions.[47] In the NEM, the Commission has considered the issue of a potential capex bias as part of its Power of Choice reform program as well as rule change requests such as:

- Economic regulation of network service providers[48]
- Demand management incentive scheme[49]
- Distribution network planning and expansion framework.[50]

45 An common example of this situation is where in the first year of a regulatory period, an NSP is expecting an increase in peak demand for the final three years of the regulatory period that was not forecast during the regulatory determination processhas increased, but it is unclear whether that forecast increased in demand will continue indefinitely or decline again: in this scenario an NSP could chose to invest in a capex solution to expand the network to meet the increased demand or an opex solution to reduce demand and defer the potential need to expand the network until a later date. Under this situation, there is a strong capex bias for assets with short lives, and a small opex bias for assets with a life greater than 40 years.

46 A description of the building block framework is set out in the report prepared by CEPA for this review. This can be found at https://www.aemc.gov.au/markets-reviews-advice/electricity-network-economic-regulatory-framew-1. Chapter 5 of the Commission's consultation paper on the *Contestability of energy services* rule change request also provides a detailed description of the framework. The consultation paper can be accessed via the Commission's website https://www.aemc.gov.au/rule-changes/contestability-of-energy-services

47 For example, the issue of capex bias has been a subject of a number of reviews by Great Britain's utility regulators Ofgem and Ofwat. The New York Public Service Commission also considered the issue of capex bias when introducing a new regulatory framework 'Reforming the Energy Vision'.

48 For more information, go to http://www.aemc.gov.au/Rule-Changes/Economic-Regulation-of-Network-Service-Providers

49 For more information, go to http://www.aemc.gov.au/Rule-Changes/Demand-Management-Embedded-Generation-Connection-I

50 For more information, go to http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Planning-and-Expansion-Framew

These rule changes (and multiple others) have strengthened incentives for efficient capital and operating expenditure and sought to encourage NSPs to seek alternatives to traditional network solutions, but have retained the split of operating and capital expenditure.

In a report prepared for the Commonwealth Department of Energy and Environment, KPMG considered that

"The regulatory framework now provides reasonable incentives for businesses to make efficient expenditure decisions when it comes to traditional network investment. Incentives are better targeted, encouraging network businesses to achieve cost savings with increased transparency on planning.[51]"

Despite the changes discussed above, stakeholders remain concerned that NSPs have an inherent bias to prefer capital expenditure over operating expenditure. A number of submissions to the Finkel Review argued that the incentives provided to NSPs under the current framework to undertake capex is stronger than the incentives to undertake opex.[52]

The Finkel Review therefore recommended the Commission to 'undertake financial modelling of the incentives for investments by distribution network businesses, to test if there is a preference for capital investments in network assets over operational expenditure on demand-side measures.'[53] The Finkel review further recommended that if the Commission's modelling demonstrates that there is a bias towards capital expenditure, the Council of Australian Governments (COAG) Energy Council should direct the Commission to assess alternative models for network incentives and revenue setting, including a total expenditure approach.[54]

2.2 Commission's approach in assessing the issue

As discussed above, NSPs' role is likely to evolve from one that conveys electricity in a one-way direction in a safe, secure and reliable manner to one that facilitates services provided by DER. Some of the services that could be facilitated by NSPs could include peer-to-peer energy trading between consumers, providing a means to support energy services provided by third party providers and services that could provide solutions to network issues such as congestion management, grid security and reliability.

Given the transformation of the electricity sector, the Commission's assessment of whether a capex bias exists has been undertaken against the backdrop of the evolving role of NSPs.

The Commission has taken a two-stage approach to the assessment:

- Stage 1: analysis of incentives under the current regulatory framework. In this stage, the Commission:
    - analysed certain performance indicators to determine whether NSPs' past investment decisions exhibited a bias toward capex

51 KPMG, *Optimising network incentives: alternative approaches to promoting efficient network investment*, January 2018, p. i.

52 *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, p. 151.

53 Ibid., p. 152.

54 *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, p. 152.

    - conducted modelling and analysis to examine whether the current framework provides incentives for NSPs to prefer capex over opex.
    - examined whether other factors might drive NSPs to prefer capex over opex (or vice versa).
- Stage 2: examine whether the current framework is fit for the future. Based on the analysis above, the Commission examined whether the current framework, if left unchanged, will be suitable for a future that is significantly different from that of today. In particular, the Commission considered future scenarios where there is a high level of renewable generation, significant penetration of DER, and where the electricity system's transformation will provide NSPs with a large selection of non-traditional solutions to network problems – much of it provided by assets owned by end consumers.

The Commission engaged Cambridge Economic Policy Associates (CEPA) to assist with the assessment of the expenditure bias. CEPA's report is published on the Commission's website.[55]

2.3 Does NSPs' past performance demonstrate a capex bias?

The starting point of the Commission's analysis was to examine whether NSPs' past performance provide any indication of bias towards capex. This analysis was conducted using publicly available data as well as expenditure data provided by the Australian Energy Regulator (AER) as part of the monitoring aspect of this Review.

Indicators examined as part of this Review

Table 2.1 provides a summary of the indicators examined by the Commission

Table 2.1: Summary of performance indicators examined by the Commission

INDICATOR	COMMENTARY
Capex-opex ratio	Capex-opex ratio fluctuated between 2006 to 2016. During the peak of high capex (between 2007 -2011), NSPs spend more than twice the amount of capex compared to opex. The ratio of capex to opex fell steadily across all jurisdictions from 2011. In 2016, ratio of capex to opex was 1.25 – the lowest in 10 years.
Actual expenditure vs regulatory allowance (for each NSPs most recently completed regulatory period)[56]	The majority of distribution NSPs' actual capex was lower than the regulatory allowance provided by the AER. In contrast, the majority of distribution NSPs actual opex was higher than their regulatory allowance. In the case of transmission NSPs, actual capex was all lower than allowance. Actual opex was also lower than

55 https://www.aemc.gov.au/markets-reviews-advice/electricity-network-economic-regulatory-framew-1

56 See Chapter 3 of CEPA's report for a more detailed discussion.

INDICATOR	COMMENTARY
	allowance, but not to the same magnitude.
Consideration of non-network solutions	The Commission has not conducted detailed analysis of NSPs' consideration of non-network options. However, the Commission notes that the AER, in its issues paper for its current review of the application guidelines for the regulatory investment tests (RIT) noted that 'there have been inconsistent levels of non-network engagement and information in reports, particularly in the non-network options report'.[57]

Past performance could not provide robust conclusion on bias

While historical expenditure (as well as other performance indicators that are available through the AER's benchmarking process) provides a useful method to observe high level trends on NSPs performance, they need to be considered and interpreted alongside some of the significant issues and changes that occurred in the electricity sector that occurred during the past ten years.

One such significant issue is the significant departure of actual demand from the forecast contained in NSPs' regulatory proposals. The reduction in capex-opex ratio and NSPs' spending less capex compared to their regulatory allowance could indicate that NSPs were responding to the changes in their operating environment, but it provides little insight on whether a bias exist or not.

The past ten years also saw the introduction of a number of major regulatory reforms. The 2012 rule change on economic regulation of NSPs provided the AER with additional flexibility when assessing regulatory proposals and introduced incentive schemes such as the CESS and DMIS. The effect of these regulatory reforms could not be easily or clearly identified in expenditure or performance data as these reforms have only been in place for a relatively short period of time.

NSPs' investment decisions could be influenced by factors other than financial incentives as discussed in section 2.5 below. However, it is difficult to disentangle their influence from a handful of expenditure indictors. Coupled with the changes in operating environment and the regulatory framework, the Commission concludes that examination of past performance is not able to provide conclusive evidence on whether NSPs' investment decisions exhibit a bias towards capex.

57 AER, Issues paper: review of the application guidelines for the regulatory investment tests, p. 26.

2.4 Does the current regulatory framework provide balanced incentives?

As the examination of past performance could not provide conclusive evidence that NSPs' investment decisions is biased towards capex, a modelling approach may provide insights on whether the current regulatory framework provide balanced incentives to NSPs when providing regulated services.

2.4.1 What financial incentives do NSPs face when providing regulated services?

Before discussing modelling outcomes, it is useful to provide an overview of the incentives faced by NSPs when they provide regulated services.

Under the incentive-based approach of regulation adopted in the NEM, the regulatory framework contains a number of mechanisms to incentivise NSPs to choose the most efficient solutions when providing regulated (i.e. monopoly) services to their customers. These incentive mechanisms can be grouped into two categories that relate to the timeframes of the regulatory period:

- **Pre-determination incentives.** Pre-determination incentives. The current economic regulation of NSPs in the NEM is based on the AER setting an NSP's maximum regulated revenue for a regulatory period at the start of that period based on estimates of the costs that would be incurred by an efficient and prudent NSP. That maximum revenue is locked in at the start of the period by the AER, even if the NSP's actual costs during the regulatory period are higher than the estimated efficient costs. This provides a general incentive for NSPs to seek efficiencies during the regulatory period as they are allowed to retain the difference between their efficient costs and the allowance until the following period, after which those savings are passed on to consumers. This contrasts with cost of service regulation used in some other countries, where regulated revenues are based on an NSP's actual costs.[58]
- **Post-determination incentives.** These are incentives schemes that apply to an NSP once it has received its revenue determination and include the efficiency benefit sharing scheme (EBSS), the capital expenditure efficiency scheme (CESS), the demand management incentive scheme (DMIS) and service target performance incentive scheme (STPIS). The EBSS and CESS were introduced to equalise incentives throughout the regulatory period for NSPs to seek opex and capex efficiencies while the DMIS was introduced to provide incentives for NSPs and implement demand management initiatives.[59] The STPIS provides incentives for distribution NSPs to deliver level of reliability that matches the value customers place on reliability.[60]

58 The AER publishes a guideline on how it calculates the rate of return. This guideline is currently under review and further information can be found at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-rate-of-return-guideline. On 14 July, the COAG Energy Council agreed to implement a binding guideline on the rate of return component of the AER's regulatory determination for electricity and gas network businesses (This decision also applies to the Western Australia's Economic Regulatory Authority regulatory decisions on Western Australia's gas network businesses)

59 CEPA's report provides a discussion on the operation of the EBSS and CESS. See Chapter 2 of the report. The AER also publishes guidelines on the operation of these schemes. For the guidelines on EBSS and CESS, go to https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/expenditure-incentives-guideline-2013. For the guideline on DMIS, go to https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism.

Table 2.2 below provides a summary of the financial incentives faced by NSPs under the current regulatory framework.

Table 2.2: Summary of incentive mechanisms faced by NSPs

INCENTIVE MECHANISM	INCENTIVE MECHANISM INCENTIVES
Expenditure assessment	• Broad incentive to seek high expenditure allowances to create a greater chance of outperformance or cover risks from higher outturn costs. • Lower future opex allowances from revealed efficiency gains. • Capex assessment typically 'one-off' based on merits of individual projects.
Rate of return	• Incentive to outperform a broad benchmark efficient entity (BEE) target rate of return allowance.
EBSS	• Equalises the opex incentive over the regulatory period. • Financial incentive to decrease opex during a regulatory period, although this leads to a reduction in base opex in the next regulatory period.
CESS	• Equalises the capex incentive over the regulatory period. • Financial incentive to decrease capex during a regulatory period, although this leads to a reduction in capex that is rolled into the regulatory asset base at the start of the next regulatory period.
DMIS	• Specific revenue reward to encourage NSPs to consider demand management solutions, which are usually opex (but could be capex). • Can influence NSP decisions pre-allowance and post-allowance.

Source: CEPA

2.4.2 Modelling financial incentives – approach

This section provides an overview of the modelling approach to provide context for discussion of the results in later sections.

60 The AER is currently undertaking its 2017 amendment of the STPIS. Information on this review can be found at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/service-target-performance-incentive-scheme-2017-amendment/draft-decision.

A brief summary of the scenarios is included in Table 2.3 to provide context. For a detailed discussion on assumptions and scenario, refer to the report prepared by CEPA for the Commission.[61]

Table 2.3: Key modelling parameters

General approach	Modelling the financial incentives that NSP face after receiving their regulatory allowances. This allows analysis on the impact on incentives as a result of the interaction between incentive mechanisms that apply to NSPs.

Modelling scenario	**Two hypothetical NSPs**
	• They have the same regulated rate of return (6% real weighted average cost of capital (WACC)), same regulatory allowance and same expected actual expenditure. When faced with a need to depart from their allowance (either through a network need or through an opportunity for efficiency gain):
	  • One NSP will choose to only focus on opex solutions– this is the OpexNSP
	  • The other will choose only to focus on capex solutions – this is the CapexNSP
	Solutions deliver the same outcome and have the same cost
	• For the purpose of modelling, the selected opex or capex solutions are assumed to provide the same outcomes for consumers and have the present value equivalent cost

Modelling scenario	Two potential circumstances that NSPs could face situations were used to conduct the analysis: **Circumstance 1** • NSPs face with a choice of equally efficient and time limited opex and capex solution. • Under this approach, it is assumed that the NSPs is implementing a solution due to a change in output or regulatory requirement and this requirement has a finite duration. At the end of the requirement period, the opex allowance for the OpexNSP will be adjusted back to the original allowance level. • A key assumption under this approach is that the EBSS is not

61 See Section 4.1 of CEPA's report for modeling scenarios and assumptions.

	applied at the end of the solution requirement as the 'base opex' allowance is adjusted for the change in outputs. **Circumstance 2** • Opex or capex efficiencies/inefficiencies are assumed to continue in perpetuity. This is the approach used by the AER in developing the EBSS and CESS. • Under this approach, if the opex efficiencies (or inefficiencies) do not occur in perpetuity the EBSS will reverse any original reward/penalty such that the NSPs should only gain/bear the time value of money.
Metric used for assessment[62]	"NPV ratio" is used as a metric to determine whether the incentives are biased. The NPV ratio assesses the relative gains/losses from underspending or overspending on a NSPs opex or capex allowance. Using this metric, a NPV ratio of 1.0 means the incentives are balanced. A NPV ratio of less than 1.0 means that incentives are biased towards capex and a NPV ratio of above 1.0 means the incentives are biased towards opex. For example, an NPV ratio of 0.5 means the NSP receives double the financial return from capex projects compared with opex projects.

Source: CEPA

2.4.3 Results under the first circumstance faced by NSPs: outcome depends on expected life of the capex solution, with a strong capex bias for short life assets

Incentives are not aligned

Under this approach, analysis indicates that incentives are not aligned and the outcome is highly sensitive to the asset life of the capex solution chosen. The results show the financial incentives are biased towards capex where the useful life of the asset is less than 40 years.

In situations where an NSP is required to address a network issue which they have not allowed for in their regulatory proposal,[63] the financial incentives to choose a capex solution is particularly strong where the expected asset life of the capex option is 10 years or less. Under this scenario, the analysis shows that the financial penalty that the NSP faces for the

62 See p. 46 of CEPA's report for further detail.

63 A common example of this situation is where peak demand has increased, but it is unclear whether that increased demand will continue indefinitely or decline again: in this scenario an NSP could chose to invest in a capex solution to expand the network to meet the increased demand or an opex solution to reduce demand and defer the potential need to expand the network until a later date.

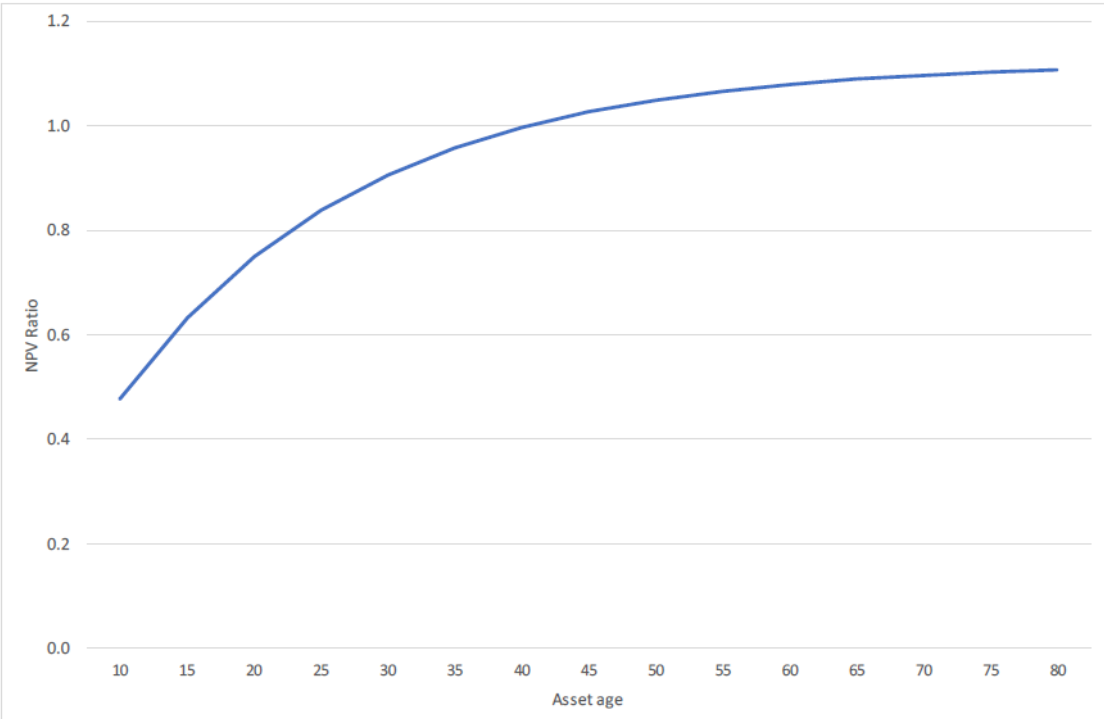
overspend (under the EBSS or CESS) is almost 50% less for the capex solution compared to the opex solution.

Conversely, if an NSP is faced with an opportunity to make efficiency savings (e.g. the NSP may have a choice of reducing expenditure in recurrent opex or in some capital investment projects), the results suggest that the incentives encourage the NSPs to make opex savings instead of capex savings where the duration of the savings is 10 years or less. Under this scenario, the reward the NSP receives for underspend (under the EBSS or CESS) is almost 50% more for the opex than for capex.[64]

In simple terms, under this circumstance, there is a strong capex bias for assets with short lives, and a small opex bias for assets with a life greater than 40 years.

Figure 2.1 provides a graphical representation of the change in incentives facing NSPs based on the expected asset life of the capex solution.

Figure 2.1: Incentives facing NSPs under the first circumstance



Source: CEPA

The misalignment of incentives is largely due to the difference in how NSPs are rewarded under the EBSS and CESS. In situations where the sharing of savings does not last in perpetuity, the EBSS provides a larger financial reward to the NSPs compared to the CESS.

DMIS helps to correct the bias

64 The implication here is that inefficient capex will remain

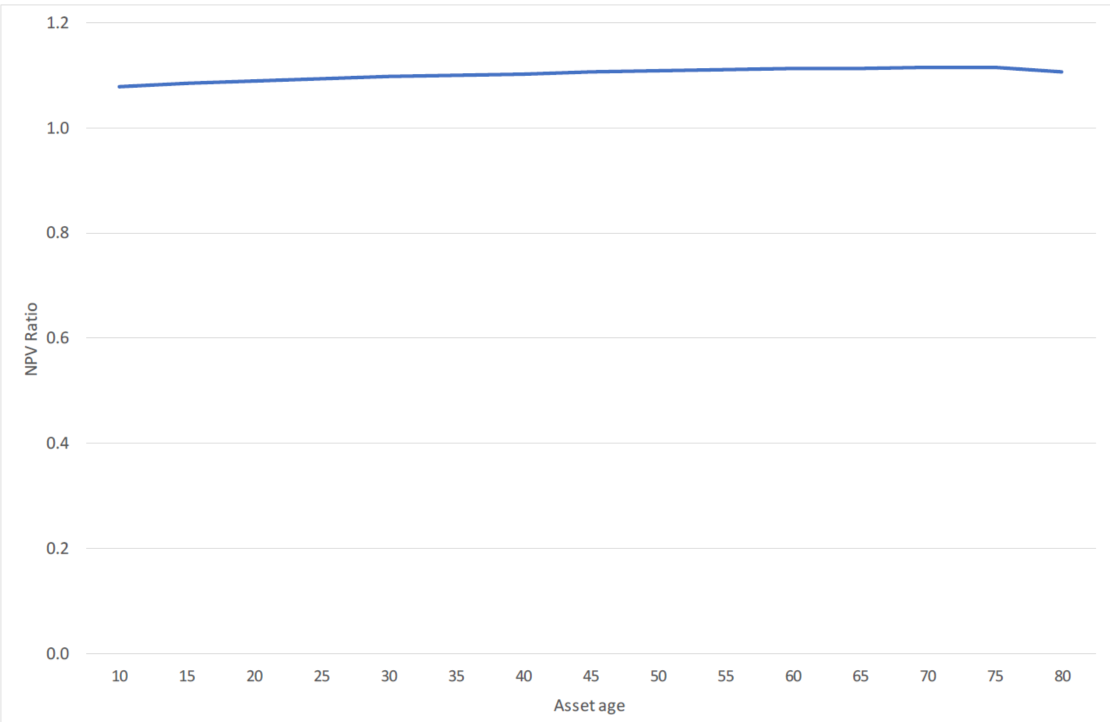
In situations where an NSPs are faced with the choice of short-life network solution (capex) and equivalent services that could be purchased from third parties (opex), the additional incentive provided by the DMIS would correct the bias towards capex solutions. However, this incentive would require additional payments from consumers. It also still results in unbalanced incentives and simply changes the tipping point at which incentives move from a capex bias to an opex bias depending on the asset life.

2.4.4 Results under the second circumstance faced by NSPs: outcome points to a slight opex bias

Incentives are not aligned, but consistently favour opex

Under this approach, the incentives between opex and capex are not aligned but slightly favour opex for all asset lives. A NSP will therefore earn a slightly higher financial return from seeking efficiencies in their capex projects compare to opex projects. For situations where the NSP needs to spend more than its regulatory allowance, it will face a smaller penalty under the EBSS by choosing an opex solution. This is illustrated graphically in Figure 2.2 below.

Figure 2.2: Incentives facing NSPs under the second circumstance



Source: CEPA

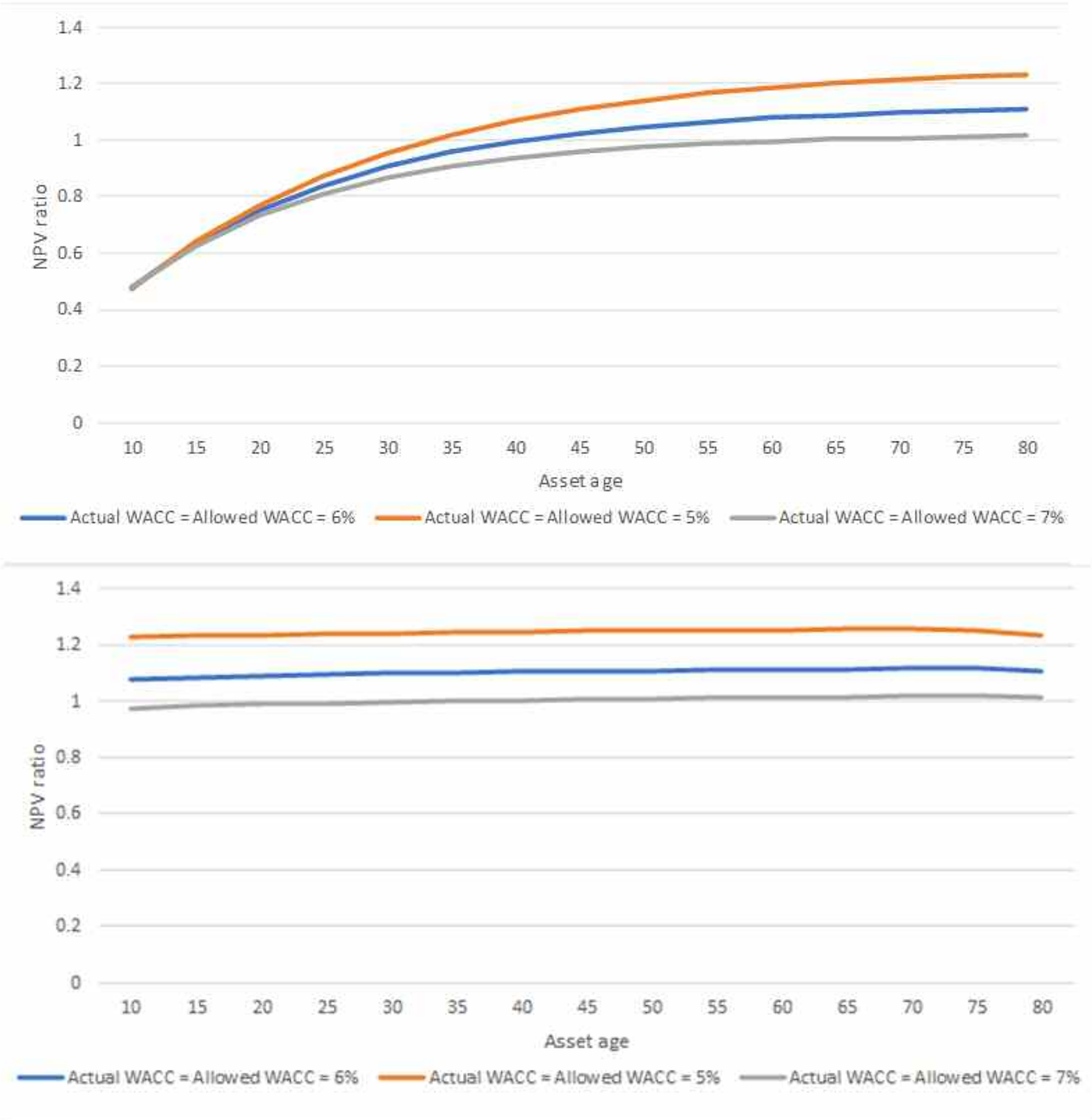
2.4.5 Does a higher or lower rate of return change the incentives?

The Commission has requested CEPA to conduct sensitivity testings as part of the analysis. One of the sensitivity tests involves testing how a higher or lower regulated rate of return would influence the modelling outcome. CEPA found that the effect of a higher or lower regulated rate of return has the same effect under both circumstances faced by the NSPs.

A low rate of return (for example, 5% instead of 6% used above) reduces the bias towards capex (or increases bias towards opex) and a higher rate of return achieves the opposite result. This effect occurs because the design of the EBSS assumes that the regulated rate of return is 6%.

Figure 2.3 below shows the effect the different regulated rate of return has on incentives. Under the first circumstance (top chart), a higher or lower rate of return does not alter the 'shape' of the incentive profile and a bias towards capex still exists for capex solutions that have short expected lives. Under the second circumstance (bottom chart), a sufficiently high regulated rate of return could switch the incentives from opex biased to capex biased.

Figure 2.3: Impact of different regulated rate of return on incentives



Source: CEPA

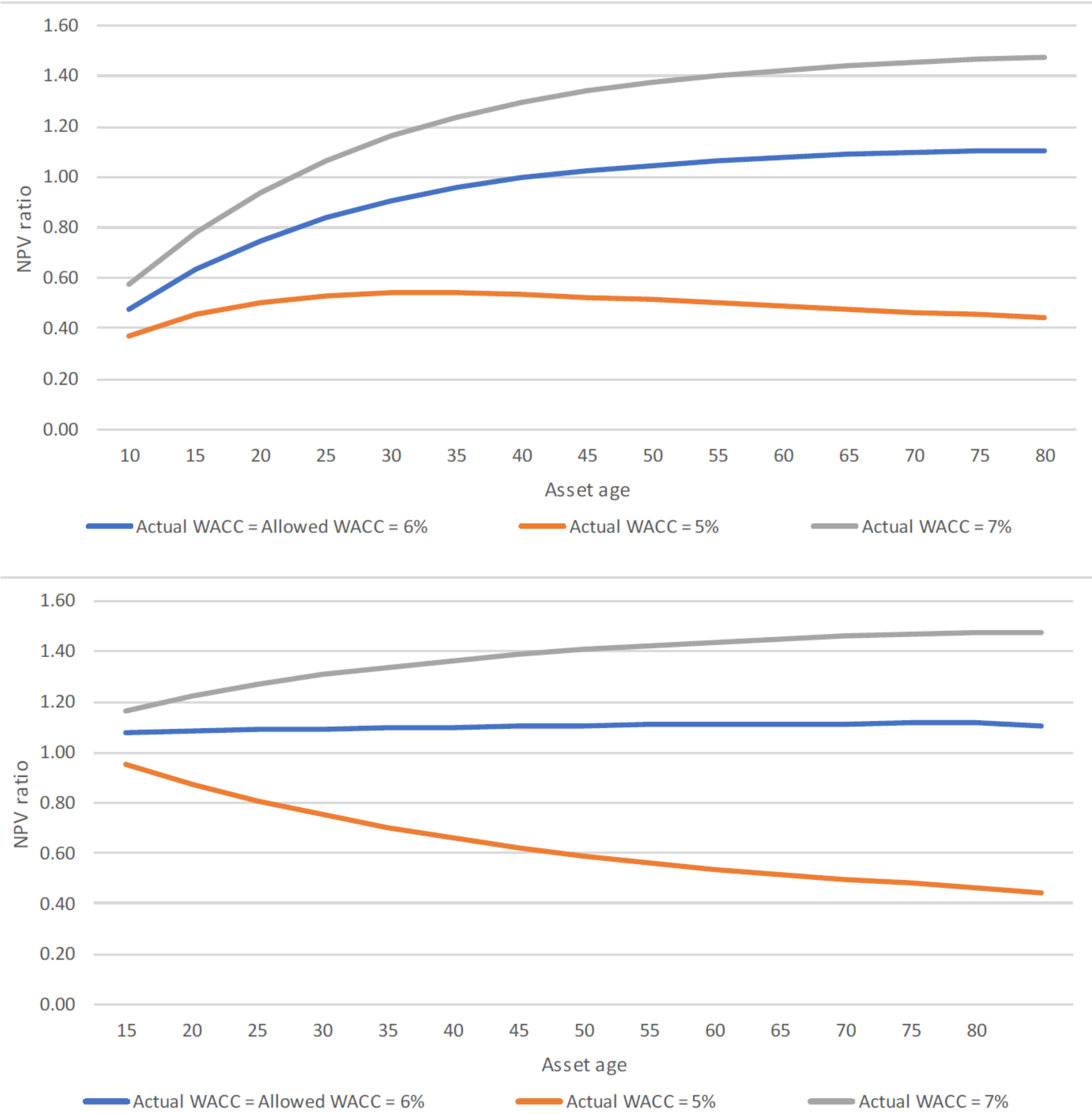
2.4.6 What happens if an NSP's expected cost of capital is different to the regulated rate of return?

Incentives are strongly biased towards capex where the NSP's expected cost of capital is lower than the regulated rate of return

The Commission's analysis shows an NSP that is able to (or expected to be able to) source funds at a rate lower than the regulated rate of return faces a much stronger incentive to prefer a capex solution. This bias towards capex solutions exists regardless of the asset life and the circumstance faced by the NSP, and increases as the asset life of the solution increases.

The orange lines in Figure 2.4 below shows the bias shifting strongly in favour of capex when the expected cost of capital is 1% lower than the regulated cost of capital. For example, under the first circumstance if the regulated rate of return is 6% but an NSP's expected cost of capital is 5%, the NSP will receive about 2 to 3 times the financial return for capex solutions as opposed to opex solutions. Under the second circumstance, NSPs receive a greater financial return for capex solutions for any asset life, with over double the level of returns for capex solutions for long life assets.

Figure 2.4: Impact of different regulated rate of return on incentives



Source: CEPA

The materiality of a bias in these circumstances will depend on the extent and materiality of any difference between the regulated cost of capital and an NSP's expected cost of capital. The size of any difference between the regulated and expected cost of capital is likely to vary between NSPs and over time, depending on a range of circumstances including the NSP's financing practices and where the economy is in the interest rate cycle. When interest rates and regulated rates of return are low, as is currently the case, the materiality of any bias arising from this issue is likely to be low. But if interest rates and regulated rates of return increase in future, the potential materiality of this bias will also increase.

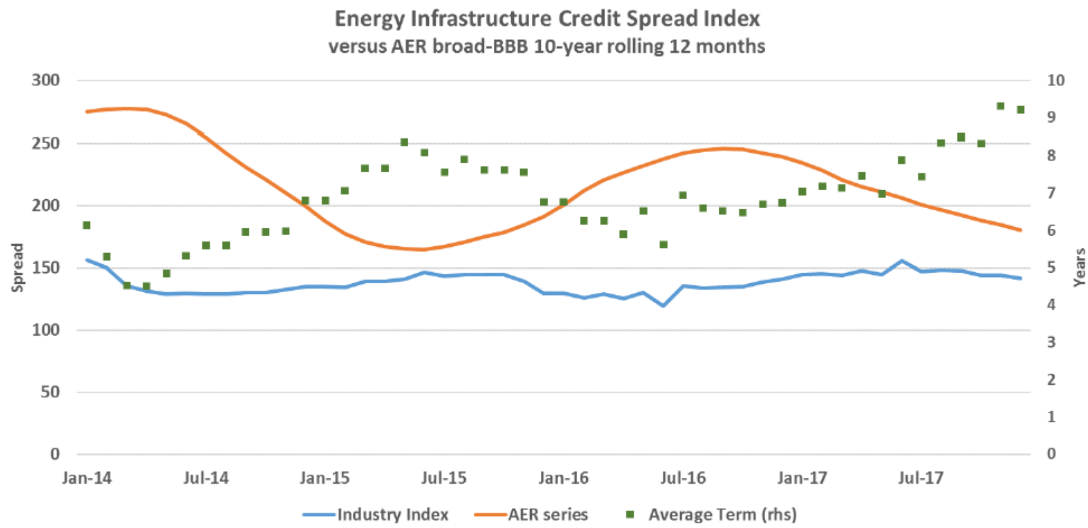
There is some evidence to show that NSPs may be able to source funds at a rate lower than the regulated rate of return. As part of its current rate of return guideline review, the AER sought actual debt information from NSPs to serve as 'sense check' on its current cost of debt estimation approach. The analysis was conducted by consultant Chairmont Group and showed that between 1 January 2013 and 31 December 2017, the simple 12-month rolling average of the 'cost of debt' of all new debt instruments raised by a total of 11 privately owned NSPs is lower than the estimated 'cost of debt' under the current approach.[65]

Figure 2.5 below compares:

- The 'Industry index'–the average credit spreads on all debt issued within the last 12 months in a sample of privately owned NSPs
- 'Average term'—the average term at issuance for all debt making up the industry index at any point in time (rolling 12 month average). In contrast, the AER approach always has an average term of 10 years.
- The 'AER series'–the average credit spreads for the past 12 months of daily credit spreads estimates calculated as:
  - A daily yield– the average of 10 year broad-BBB estimates using the BVAL and RBA third party yield curves; less
  - The Australian Dollar swap rate with a 10 year term to maturity.

65 See Chapter 7 of AER's Discussion paper: estimating the allowed return on debt. The report can be found on the AER's webpage on rate of return guideline review: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-rate-of-return-guideline/initiation

Figure 2.5: Impact of different regulated rate of return on incentives



Source: AER

The AER released its draft decision on it rate of return guideline review on 10 July 2018. The AER estimated that its draft decision will result in a 45 basis point reduction in the overall rate of return compared to its previous approach.[66] The potential reduction in the regulated rate of return may have a significant impact in reducing the potential for bias in the future. However, given that the regulated rate of return is set based on the financing costs that would be incurred by an efficient benchmark entity, it is not possible to set a regulated rate of return that will match the expected cost of capital of all NSPs. It is almost inevitable that some NSPs will have expected costs of capital that are materially less than the regulated rate of return, and some NSPs may have expected costs of capital that are materially higher than the regulated rate of return. Accordingly, this bias cannot be removed through simply setting the "right" regulated rate of return.

2.5 Are there other factors that may influence NSPs' preference for opex or capex?

NSPs run complex businesses and the Commission is aware that investment decisions are not made purely on financial incentives alone. The Commission has therefore considered whether factors other than financial incentives will influence NSPs' investment decisions.

In the report prepared for this review, CEPA presented a number of potentially relevant factors that may contribute to a capex bias:

- Shareholders' focus on regulatory asset base (RAB) growth

66 AER, *Draft rate of return guidelines: explanatory statement*, p. 18.

- Risk aversion
- Reputational incentives and NSP culture.

The following sections discuss these factors in more detail.

2.5.1 Shareholders' focus on RAB growth

CEPA's research indicate that anecdotally, investors of regulated businesses have a preference to stable long term returns associated with the RAB-based approach under the current framework. Investors appear to be concerned that moving away from asset base growth or maintenance will reduce the level of future profits and future growth.

CEPA's report noted that investors' preference for RAB growth appears at odds with economic theory which suggests that an investor's ability to earn above their opportunity cost of capital lies not in growing the RAB per se but in whether the NSP's actual cost of capital is lower than its regulated allowance. CEPA therefore also examined whether other factors such as preferences for long term stable cash flows could influence this preference.

CEPA analysed a selection of analyst commentaries for both Australian and international energy businesses and found that they are generally consistent with the view that RAB growth is perceived as a generally desirable outcome in investors' consideration of regulated businesses, regardless of whether the regulated return is more or less than the actual cost of capital. Table 7.4 reproduces some of the analyst commentaries from CEPA's report.

Table 2.4: Sample analyst commentary on the desirability of RAB growth

ANALYST/COMPANY	COMMENTARY
Credit Suisse, on Spark Infrastructure	"The [2015 – 2020 regulatory] proposal put forward by SAPN calls for a 50% increase in capex allowance versus the previous regulatory period ... Capex is important as it determines the ability to grow earnings and dividends over time."
Macquarie on DUET	"… RAB is not growing, thus making it very difficult for DUE to deliver materially more than inflationary RAB growth across the DUE group." "DUE has limited RAB growth and faces the pressure of regulatory resets in 34% of its asset in CY16 which will ultimately influence its ability to maintain or grow its dividend".
Credit Suisse, on National Grid UK	"[A]sset base growth underpins the business model" and that National Grid "think that RAB growth and low interest rates can help the shares provide ongoing returns of c8-

ANALYST/COMPANY	COMMENTARY
	10%".[67] "Capex and RAB growth is the most important part of NG's bottom-up investment case. .... RAB growth is now the key lever NG has left to grow and try to deliver returns and reach the company's c8-10% p.a. total return objective. … The stock trades on a high premium partly because it has growth, and it has growth because it trades on such a high premium and can get the value creation. The possibility for this circularity turning from a virtuous circle into a vicious circle if capex falls is why we are so concerned about this."

Source: CEPA

CEPA considered that if investors have a preference for RAB-based growth, it is likely that they would provide incentives (e.g., bonuses) for management to deliver outcomes that aligned with their preferences,[68] thus creating a preference for capex solutions.

2.5.2 Risk aversion

Closely associated with the preference for RAB-based growth is the investors' or NSPs' perception of risk. Investors who prefer long term stability may not prefer opex solutions if they are considered to be 'higher risk'. Some of the reasons for this perception include:

- **Uncertain regulatory treatment.** Uncertainty around how long-term contracts for services would be treated within the regulatory cost assessment process if the contract term extended beyond one regulatory period. This is because under the current framework capex, once approved by the AER, will enter the RAB and no future review is conducted. However, for opex, the regulatory process allows the AER to examine all opex for efficiency, regardless of whether a portion of the opex was approved in a previous regulatory period.
- **Lack of control and uncertainty on performance.** NSPs may be concerned that innovative opex solutions may not deliver the performance required by the NSP or the asset providing the service will not perform when required because the NSP does not have control of the asset.[69]

67 Credit Suisse (2016a), page 4.

68 CEPA, *Expenditure incentives faced by network service providers*, p. 65.

69 Ibid, p. 66

There is also a perception that opex is more risky because it does not provide a 'risk-based return' compared to capex. This concern may have merit in a future where opex solutions become the primary and most efficient means for NSPs to address their network problems. Under this future scenario, a framework that only provides a return on capital investment may not provide NSPs with sufficient working capital to cover the cost uncertainty associated with long-term opex based solution. It is important to note CEPA's comment that 'simply increasing the allowed rate of return will not result in a shift to opex approaches and indeed the existing issues [as shown by the modelling results in Section 2.4] would be exacerbated by this approach'.[70]

2.5.3 Reputational incentives and NSP culture

CEPA considers reputational incentives and NSP culture are highly qualitative factors and that it is difficult to put a robust view on the weight that NSPs might place on reputational factors[71] or how an NSP's internal culture and management skill sets may influence its investment decision making process.[72] However, anecdotal evidence in the form of statements in regulatory submissions and annual reports indicate that NSP management may place quite a high weight on these factors.

Staff of several NSPs have also commented to Commission staff that under the current regulatory regime, capex earns a return on equity through the regulated rate of return but opex operates as a "pass through" with no margin. These NSP staff have commented that there is accordingly limited incentive to invest in opex solutions. This has led some NSPs to propose that the regime should be amended to include a return on opex, or that the DMIS should be extended to transmission NSPs to provide an increased return on opex solutions related to demand management.

The fact that the regulated rate of return includes a return on equity will also lead to the outcome that an NSP that spends a higher proportion of its expenditure on capex will earn a higher net profit, and likely be able to distribute higher dividends to shareholders, compared with an NSP that spends a higher proportion of its expenditure on opex. As noted by CEPA, this outcome is economically efficient as an NSP with higher opex and lower capex requires less capital and therefore investors could earn returns on their capital elsewhere and should be indifferent to these outcomes. However, if the performance and remuneration of NSP management is linked to the NSP's net profit or other similar measures, this is likely to create a cultural bias in management to prefer capex solutions that increase net profit. A cultural bias may also arise due to reputational impacts, with management likely to prefer approaches that increase profits, particularly given the comments above that indicate that analysts see RAB growth as desirable and unpinning NSPs' business models, with management are likely to be influenced by the views on analysts on their investment strategies.

70 Ibid, p. 65

71 CEPA considered some of the reputation factors may include: providing the distribution standard network services and prescribed transmission services in a reliable and safe way; and being identified as providing efficient delivery of these services

72 Ibid, p. 62

The impact of cultural issues and management incentives is likely to vary between NSPs depending on a range of factors including the nature of the NSP's shareholders. For example, an NSP whose shareholders prefer stable long-term returns (for example superannuation funds) may prefer capex. However, an NSP whose shareholders are listed entities may put a higher weight on short term cash flow and be reluctant to commit significant amounts of capital to fund major capex projects and therefore may prefer opex (or short life capex assets).

2.6 Commission's findings

2.6.1 Outcome varies depending on individual circumstances, but incentives for capex and opex are not aligned

The Commission's analysis does not show a systematic bias towards a particular type of expenditure, as the outcome is dependent on the circumstances faced by the NSP. However, the analysis does show that the incentives for capex and opex are not balanced under the current regime, with the potential for a significant capex bias in certain circumstances.

Implications of the modelling outcome

Where the solution to a network problem is time limited (the first modelling approach), analysis shows that for assets with long expected life, the NSP should be indifferent to whether the solution utilises opex or capex as the framework provides reasonably balanced incentives. This outcome would be appropriate from a financial perspective in a world where network problems generally require solutions based on long lived assets, which has largely been the case for traditional network solutions in the past.[73] In a future scenario where technology continues to improve, NSPs are likely to have many more solutions compared to traditional network solutions and an increased proportion may involve opex or assets with much shorter life (for example battery storage). The solutions with short lived assets could potentially have equivalent opex solutions. For example, an NSP may face the option to install and own its own battery using capex or procure battery services or demand response provided by third parties from the competitive market. Under this scenario, an NSP's decision could be influenced by the option that provides the greatest financial return as opposed to the most efficient option.

While the DMIS provides additional incentives to offset possible capex bias, it would require the NSP to consider the combined effect of the EBSS, CESS and DMIS. This complexity may cause unintended consequences. The Commission also considers that a framework that creates different financial outcomes based on different solutions may not provide NSPs with the appropriate incentives to select the least cost solution but one that provides the greatest financial return.

Where an NSP's expected cost of capital is lower than the regulated rate of return, incentives are strongly biased towards capex

73 This discussion here is focused on the NSP's investment based purely on financial incentives. In reality, NSPs may consider other non-financial factors when deciding on their investment solution. The impact of non-financial factors on NSPs' decision making was discussed in Section 2.5.

Where an NSP expects to be able to source funds at a rate lower than the regulated rate of return, the analysis indicates that the current framework always provides a strong bias towards capex solutions, and that bias is the strongest for capex solutions that have long expected asset life (e.g. a traditional network poles and wire solution).

The Commission considers the outcome illustrated by this sensitivity testing has significant implications on the regulatory framework, especially in a future where there are a variety of solutions to a given network problem. In such as future, investment decisions that favour long-lived capital asset may lead to unnecessary network price increase, which may in turn lead to consumers making inefficient decisions on alternatives to grid-supplied energy, thus increasing the risk of asset stranding. In the near term, a strong incentive to prefer capex solutions could also hinder the development of the competitive energy services market. The Commission considers these outcomes are not in the long term interest of consumers and that measures should be taken to address this issue.

It is important to note that any potential bias may not be caused by a single factor, but rather as a result of a combination of factors such as the asset life of potential solutions as well as the an the magnitude of difference between an NSP's expected cost of funds compared to the regulated rate of return.

In the current environment where interest rates and regulated cost of capital are low, and where the most viable solutions to many network problems may still require capital investment, the Commission's view is that the potential for bias is low and the current regulatory framework provides appropriate incentives for efficient investment decisions. However, the Australian electricity system is likely to be highly decentralised in the future,[74] and DER are likely to be able to provide plausible alternatives to traditional network solutions. The Commission is concerned that the potential for bias would be greater under such a scenario, especially when combined with a high interest rate environment.

Other factors influencing bias: perceptions matter

While the perception of bias is largely anecdotal, the Commission considers that this perception is likely to have a large impact on NSPs' preference for capex over opex. The Commission arrives at this conclusion after considering the evidence presented by CEPA in its report as well as stakeholders' comments during consultation for this review and recent rule change requests.

Many stakeholders, including some NSPs, hold the perception that the current framework provides incentives for NSPs to prefer capex over opex, despite recent reforms that were introduced to better balance the incentives between capex and opex. Similar to Ofwat's conclusion when it investigated the issue of bias in 2011, the Commission considers the widespread perception that a bias exists may create a self-fulfilling belief which in turn may drive NSPs' behaviour.

74 Bloomberg New Energy Finance's (BNEF's) New Energy Outlook 2018 indicates that by 2050, the Australian energy system will be one of the two most decentralized energy system in the world, with consumer PV and behind-the-meter batteries making up 44% of all capacity.

2.7 Commission's conclusion

The importance of balanced expenditure incentives to support the electricity sector transformation

In the Distribution Market Model report, the Commission discussed the need for the distribution system to move towards a distribution level market where DER are more actively controlled in order to realise the multiple value streams of DER. This may entail the role of NSPs (distribution NSPs in particular) changing from a simple conveyer of one-way electricity to one that facilitates the investment and operation of DER. Distribution NSPs are also likely to become more significant purchasers of DER and other non-network solutions from third parties as an alternative to traditional network capex solutions. The Commission considers expenditure incentives will play an important role in these changes and that the potential or a perception of bias is likely to prevent the full value of DER from being realised.

The transformation of the electricity sector and the evolving role of NSPs will require a regulatory framework that provides flexibility to enable NSPs to adapt to the continually changing environment and appropriate incentives for NSPs to make the most efficient investment decision, regardless of whether the solution may involve capital or operating expenditure. Such a framework, underpinned by incentive based regulation, would help unlock the value that DER can provide to both end consumers and the electricity industry.

Separate operating and capital expenditure assessment and remuneration is not likely to be suitable for a future with high DER penetration

The issue of expenditure bias is due largely to the current method of separate assessment and remuneration opex and capex. In a future with high DER uptake and increased availability of non-network solutions using new technologies, the separate assessment and remuneration of capex and opex is not likely to lead to the most efficient outcome for the following reasons:

- **Separate operating and capital expenditure assessment and remuneration may not be the most appropriate approach in the future given the predicted growth in non-traditional solutions.** The building block framework and associated expenditure assessment and remuneration methodology that underpin the current economic regulatory framework was created at a time where the efficient and safe conveyance of electricity required investment in capital intensive and long-lived assets. While the fundamental features of this framework and its incentive-based approach remain sound, there is a risk that this approach may not adequately cater for the growth of non-traditional (and often opex-based) solutions and their ability to provide credible alternative to capex options. As a result, reforms to the current approach of separately assessing and remunerating operating and capital expenditure will be required to address the potential different business risk that come with a significantly higher level of opex that an NSP may incur in the future.
- **The system of incentives risks becoming too complex.** Over time, a system of incentive schemes have been introduced to encourage NSPs to undertake efficient investment, reduce costs as well as seek non-traditional solutions while maintaining

service level standards. However, as the preceding analysis showed, the incentive mechanisms have become quite complex and their combined effect depends heavily on assumptions and individual circumstances. As the variety of solutions to network problems increase, this complexity is likely to cause unintended outcomes where NSPs may respond to incentives incorrectly.

Incremental changes to current incentive schemes are not likely to be sufficient

The above discussion indicates that incremental changes to the current incentive mechanisms are not likely to be sufficient or appropriate to address the biased incentives in the framework nor are they likely to address stakeholders concerns or perceptions about biased incentives.

Overseas regulators such as Ofwat had attempted to address similar issues in the past by using a combination of mechanism similar to the EBSS and CESS. However, Ofwat concluded that the combination of such mechanisms was not able to provide the balance required and that a system that removes the different arrangements for opex and capex was required. CEPA also concludes that it is unlikely to be possible to make changes to the various current incentive mechanisms (EBSS, CESS and DMIS) so that they provide equal incentives for capex and opex in all circumstances, and that no overseas regulator has been able to achieve that outcome through changes to equivalent overseas incentive schemes.

2.8 Next steps

The Commission’s monitoring indicates that the penetration of DER is likely to continue to increase in the future. In light of this, the Commission considers a holistic review of the method of expenditure assessment and remuneration is required to support the continual transformation of the electricity sector. The Commission also recognises that a departure from the current arrangements would require significant lead time, stakeholder consultation and close collaboration between the industry as well as market bodies such as the Commission and the AER.

As part of the 2019 economic regulatory framework review, the Commission will commence consultation on changes required to the expenditure assessment and remuneration systems to enable the economic regulatory framework to continue to support the electricity sector’s transformation. The Commission will commence this work immediately following the publication of this report.

3 NETWORK SERVICE PROVIDERS' EXPENDITURE TRENDS

Summary of key observations

- The National Electricity Market (NEM) saw significant growth in the regulated asset base (RAB) of distribution network service providers (NSPs) for several years up to 2014-15, but over last few years the combined RAB has levelled off with minimal growth being observed recently.
- There has been a sharp decline in capex since 2012-13, with the lowest level of capex in 10 years being recorded in the latest year of reporting.
- Transmission NSPs' RAB saw a similar trend of historical growth followed by plateauing in recent years.
- Some commentators consider that there has been an over-investment in network infrastructure and have called for write-downs of RAB values.
- The Commission considers that more targeted measures such as extending the Australian Energy Regulator's (AER's) power to conduct ex-post reviews of capital expenditure will provide a better measure to manage the risk of overinvestment in the future.

As part of the Review, the Commission monitors on an annual basis some of the key performance indicators for network service providers (NSPs). The results of the monitoring form part of the Commission's assessment of whether NSPs are responding to changes in the market and whether changes to the regulatory framework are required.

This year's monitoring update is limited to metrics of investment in network infrastructure with a focus on distribution NSPs. The Commission notes that investment in electricity network infrastructure has been a recent topic of interest, and this section outlines the Commission's observation of key recent trends. Unless stated otherwise, all values in this section are in 2017 dollars.[75]

3.1 Trends for distribution NSPs

3.1.1 Distribution NSP RAB

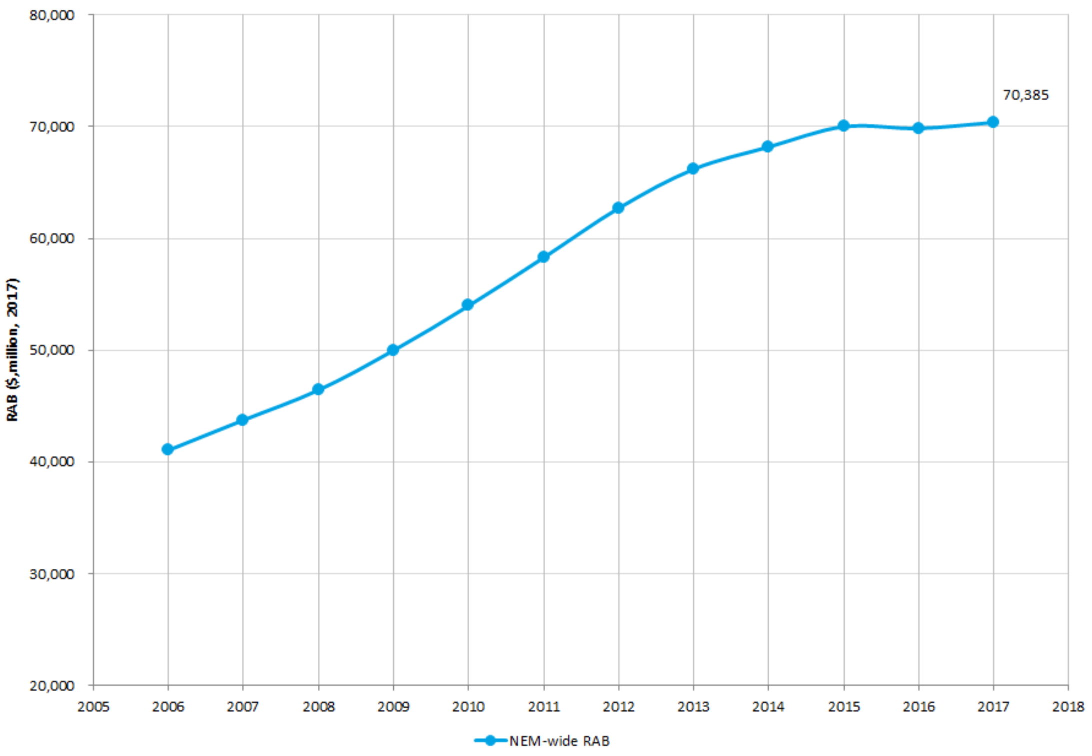
Figure 3.1 below shows the combined closing regulated asset base (RAB) for all distribution NSPs in the national electricity market (NEM).[76] It can be seen that the combined RAB across the NEM saw significant growth for several years up to 2014-15, but over last few years the

75 All financial data is adjusted to June 2017 terms using CPI data from the Australia Bureau of statistics.

76 Please note that 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 2016-17 financial year is represented as 2017 data for the NEM wide analysis.

RAB has levelled off with minimal growth being observed recently. Over the last three years, the combined RAB has been flat at approximately $70 billion.

Figure 3.1: Combined closing RAB of distribution NSPs in NEM



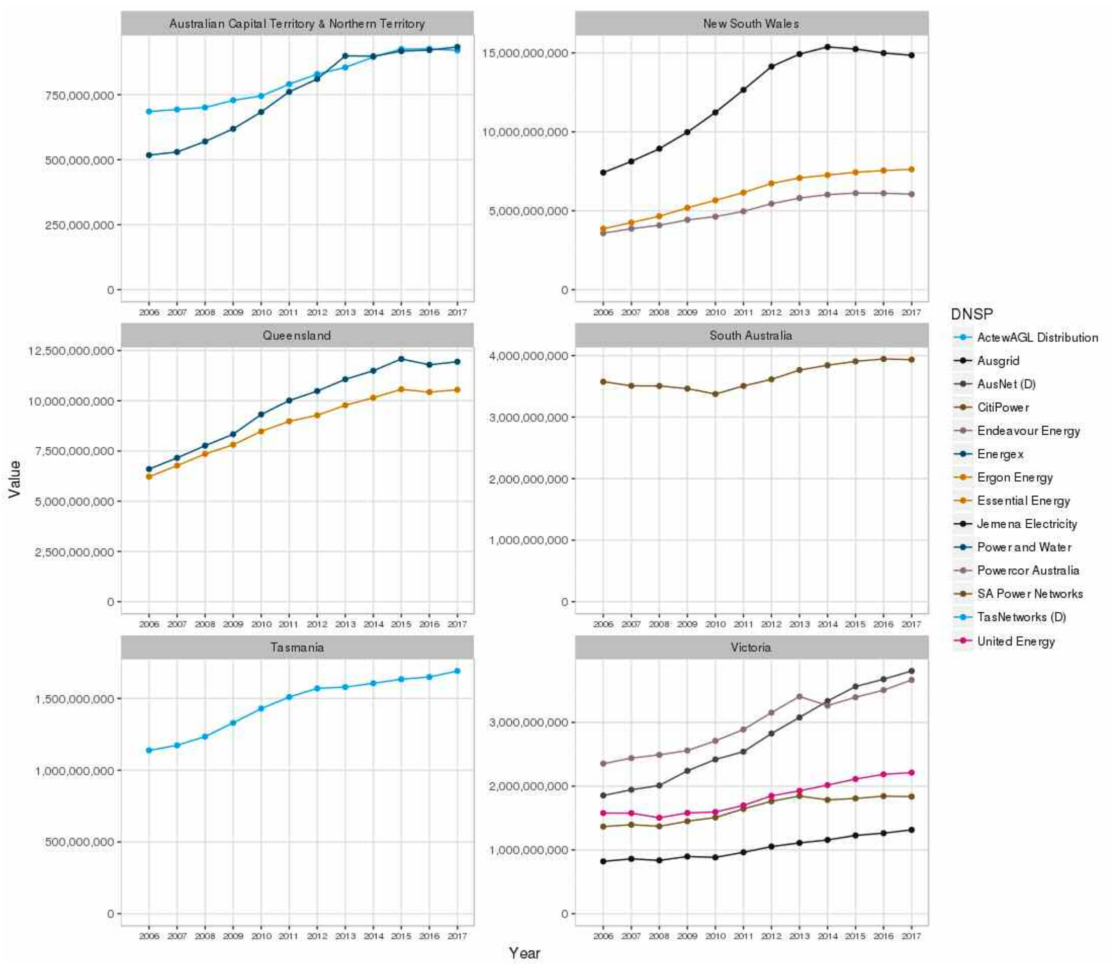
Source: AER
Note: values in 2017 real dollar terms.

The historical growth of RAB has been the subject of many studies and commentators have attributed several factors to the period of significant RAB growth between 2006 and 2014 such as increased reliability standards for Queensland and New South Wales, unprecedented changes in peak demand, and ownership structure of some distribution NSPs.[77] Some commentators consider there has been an over-investment in network infrastructure and have called for the write down of the value network RABs.[78]

77 Independent Review Panel on Network Costs, *Electricity Network Costs Review Final Report*, 2014, p.42; Mike Sandiford, Tim Forcey, Alan Pears and Dylan McConnell, *Five years of Declining Annual consumption of grid-supplied electricity in Eastern Australia: Causes and Consequences*. The Electricity Journal Volume 28, Issue 7, August-September 2015; Grattan Institute, *Down to the wire: A sustainable electricity network for Australia*, March 2018

78 Grattan institute, *Down to the wire: A sustainable electricity network for Australia*, March 2018, p.3.

Figure 3.2: Distribution NSP RAB



Source: AER.
Note: values in 2017 real dollar terms.

Figure 3.2 shows the RAB for every distribution NSP in the NEM across the reporting periods. It can be seen that the historical growth in RAB was faster for some distribution NSPs than others. For example Ausgrid in New South Wales (NSW) saw a very large increase in RAB between 2006 and 2014, but its RAB has fallen since then. Similarly Ergon Energy and Energex in Queensland historically saw faster growth in RAB, whereas a more steady growth was experienced by distribution NSPs in Victoria. The sudden dip in RAB for Queensland distribution NSPs between 2015 and 2016 can be attributed to the movement of metering from being part of the standard control services to alternative control services.[79] More recently there has been limited RAB growth seen across most of the states with the exception of Victoria, which continues to see a steady growth in RAB.

79 Confirmed by AER via email on 25 May 2018.

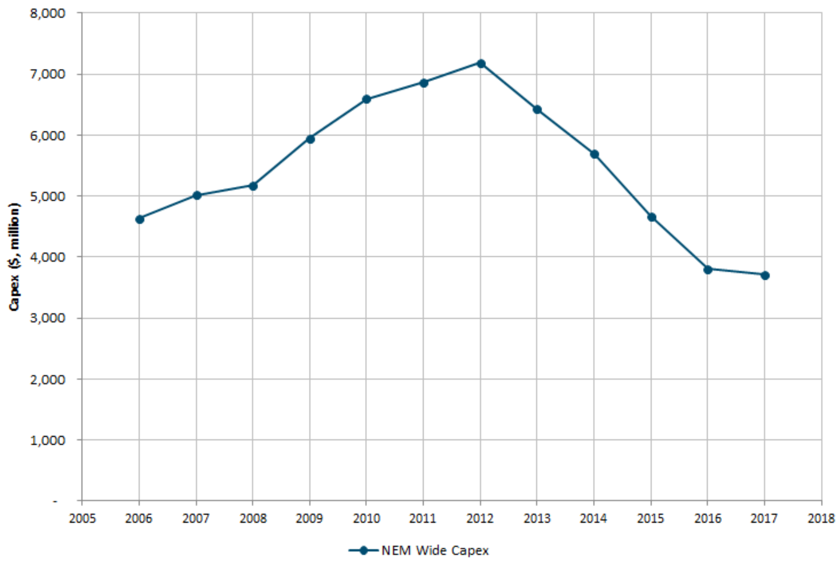
The observed overall trend of plateauing RAB levels after a period of significant growth may be linked to several factors including:

- the plateauing of maximum grid demand in recent years after a period of steady growth[80]
- changes to the jurisdictional reliability requirements reducing their degree of prescription
- reforms to the network economic regulation carried out by the Commission giving the AER greater flexibility over the method it uses to determine revenues and clarifying the AER's powers to interrogate, review and amend capital and operational expenditure allowances based on benchmarking and subsequent decisions by the AER.[81]

3.1.2 Distribution NSP Capex

One of the major factors impacting the RAB is the level of capital expenditure (capex) in the network. From figure 3.3 below, it can be seen that the combined annual capex in the NEM was rising until 2011-12, after which point a sharp trend of decline was observed. This turning point in capex is likely to represent the inflexion point in the RAB trend. The reduction in capex is likely to be a key driver of the plateauing RAB levels observed over the last few years. It is also noteworthy that the latest cycle of reporting captured the lowest level of capital expenditure in networks observed in the last 11 years, although it was only a small decline from the previous year. The level of capex seen in the last year is almost half of the capex seen during the peak in 2011-12.

Figure 3.3: Combined distribution NSPs Capex in NEM

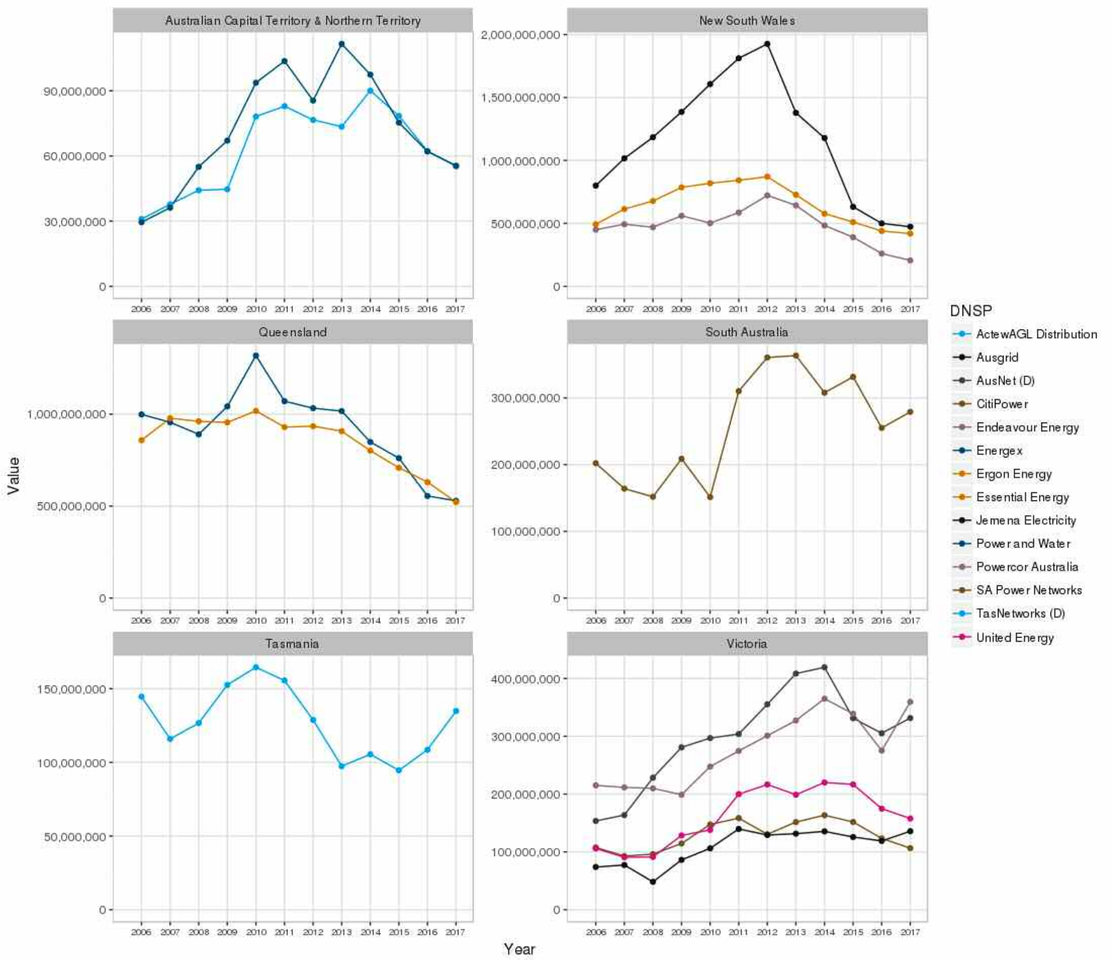


Source: AER
Note: values in 2017 real dollar terms.

80 AER, *State of the Energy Market Report 2017*, May 2017, p.26.
81 AEMC, *Final rule: Economic Regulation of Network Service Providers*, November 2012.

Figure 3.4 below shows the capital expenditure carried out by each distribution NSP in the NEM. It can be seen that there are differences in the capex trends seen across different distribution NSPs. The capex trends observed for Ausgrid and Energex are noteworthy as they saw a very sharp decline in capex from 2012 and 2010 onwards respectively. The similarity of the capex trend of Ausgrid and the overall NEM capex is also noteworthy, indicating the level of impact Ausgrid capex had on that of the combined NEM.

Figure 3.4: Distribution NSP Capex



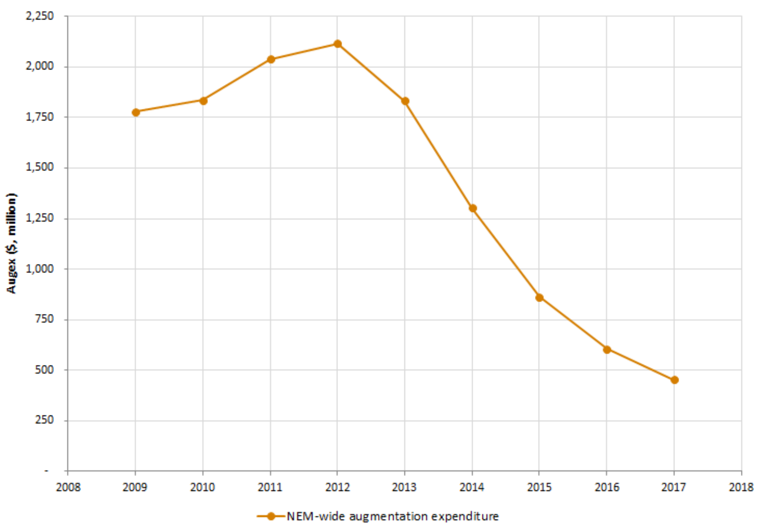
Source: AER
Note: values in 2017 real dollar terms.

The remaining distribution NSPs in NSW saw an increase at a similar time as Augrid but to a lesser magnitude. The overall trend of capex in NSW over the last few years has been downwards. Queensland has also seen a decline in the recent years following initially steady levels. The capex levels in South Australia, Australian Capital Territory (ACT) and the Northern Territory (NT) have been quite volatile but have recorded a general trend of reduction in recent years. Victorian distribution NSPs generally saw a slower in increase in capex, but over the last few years have reported a slight decline.

The major components of network capital expenditure are augmentation and replacement expenditure. Augmentation expenditure is defined as the capital expenditure primarily required to increase the capacity of the network to allow for load growth.[82] Augmentation expenditure may also be undertaken to maintain quality, reliability and security of supply in accordance with legislated requirements.[83] Replacement expenditure is the non-demand driven replacement of an asset the end of its economic life cycle.[84]

Figure 3.5 below shows the combined augmentation expenditure by distribution NSPs in the NEM across the past several years. It can be seen that there is a significant similarity in the trend observed for capex and augmentation expenditure. An increasing trend in augmentation expenditure peaked in 2011-12 and a continued trend of decline has been observed since. Similar to capex, the last reporting year for augmentation expenditure saw the lowest recorded level in the data. The latest data reported augmentation expenditure of below $500m across the NEM, which is less than a quarter of the level seen during the peak in 2011-12. This level of augmentation expenditure represents less than 1% of the total distribution NSP RAB value in the NEM, indicating a slowed growth rate.

Figure 3.5: Combined distribution NSP augmentation expenditure in NEM



Source: AER
Note: values in 2017 real dollar terms.

Figure 3.6 below shows the augmentation expenditure (augex) for each distribution NSP across the past several years. Similar to the capex trend, the distribution NSPs in NSW saw

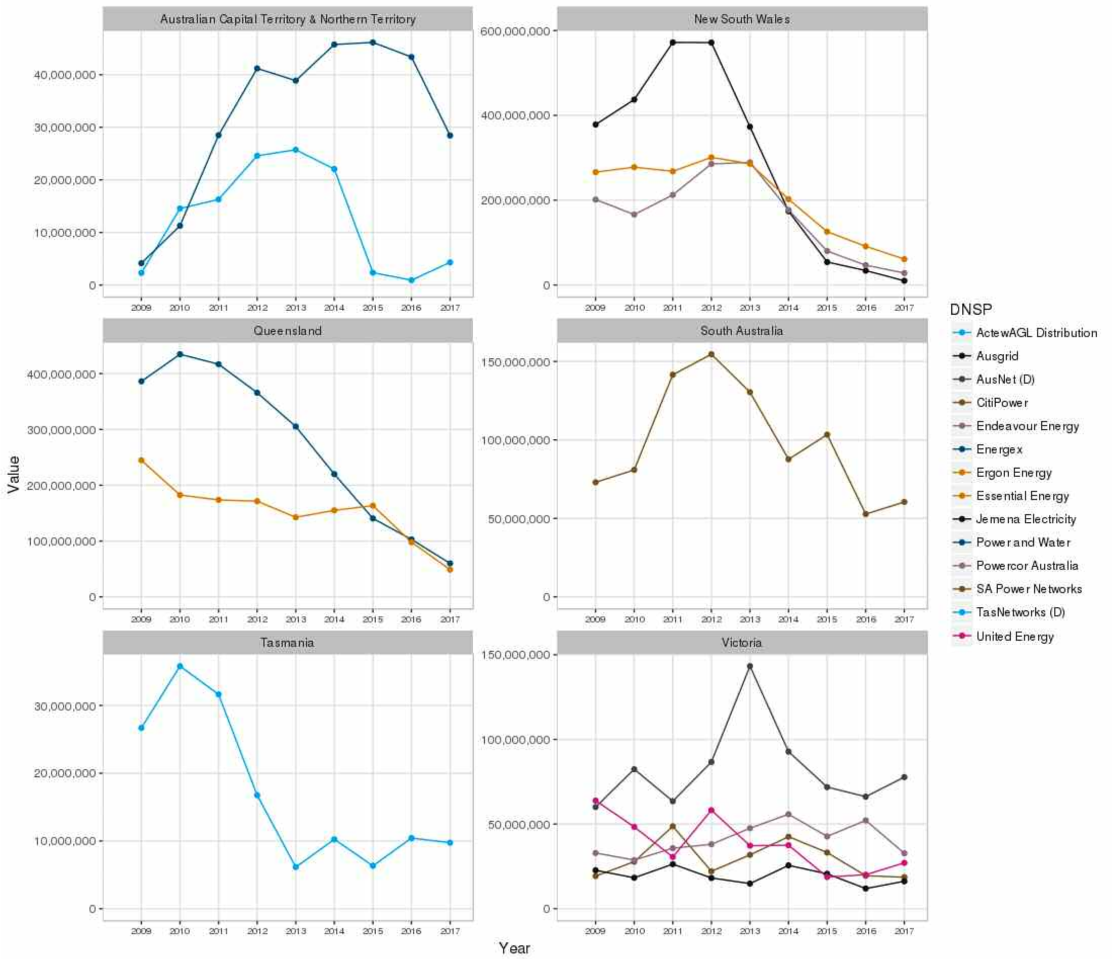
82 AER, *Guidance document: AER Capex model – data requirements*, p.4.

83 AER, *Expenditure forecast assessment guideline for electricity distribution*, p.27.

84 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.

very high levels of expenditure in 2011-12 followed by a very sharp decline ever since then. Queensland has also seen reducing augmentation expenditure over the past several years. Energex saw a drastic shift in augmentation expenditure from very high levels in 2010 to a low level in recent years. The ACT, NT and South Australia saw significant volatility in their augmentation expenditure, suggesting lumpy investment patterns for network augmentation. The augmentation expenditure levels in Victoria have remained steady over the years, with the exception of AusNet services reporting a significantly higher level of augmentation expenditure in 2013.

Figure 3.6: Distribution NSP augmentation expenditure

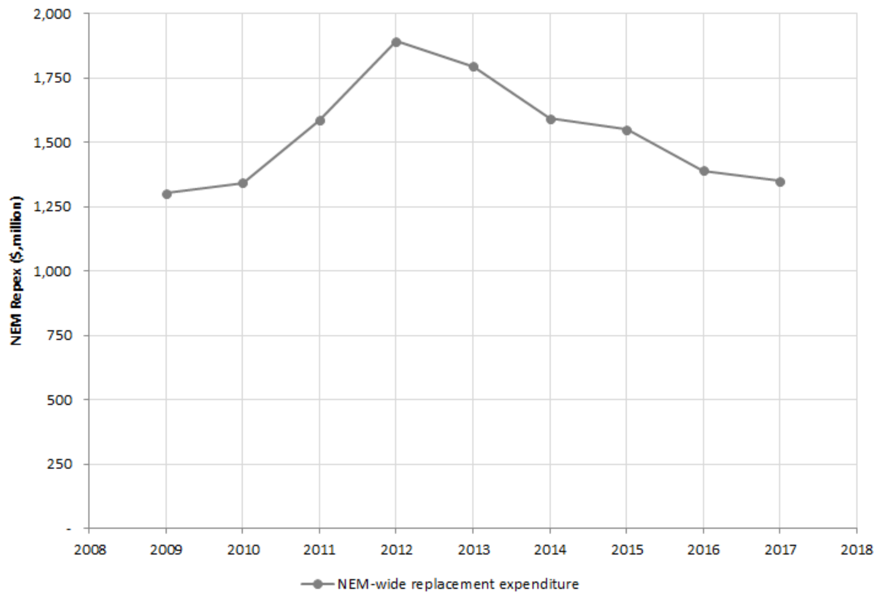


Source: AER
Note: values in 2017 real dollar terms.

Figure 3.7 shows the combined NEM distribution NSP network replacement expenditure (repex). It can be seen that the combined replacement expenditure has not changed significantly over the reporting years and the trend less closely matched the observed capex trend. A trend of reduction in recent years can also be observed in replacement expenditure.

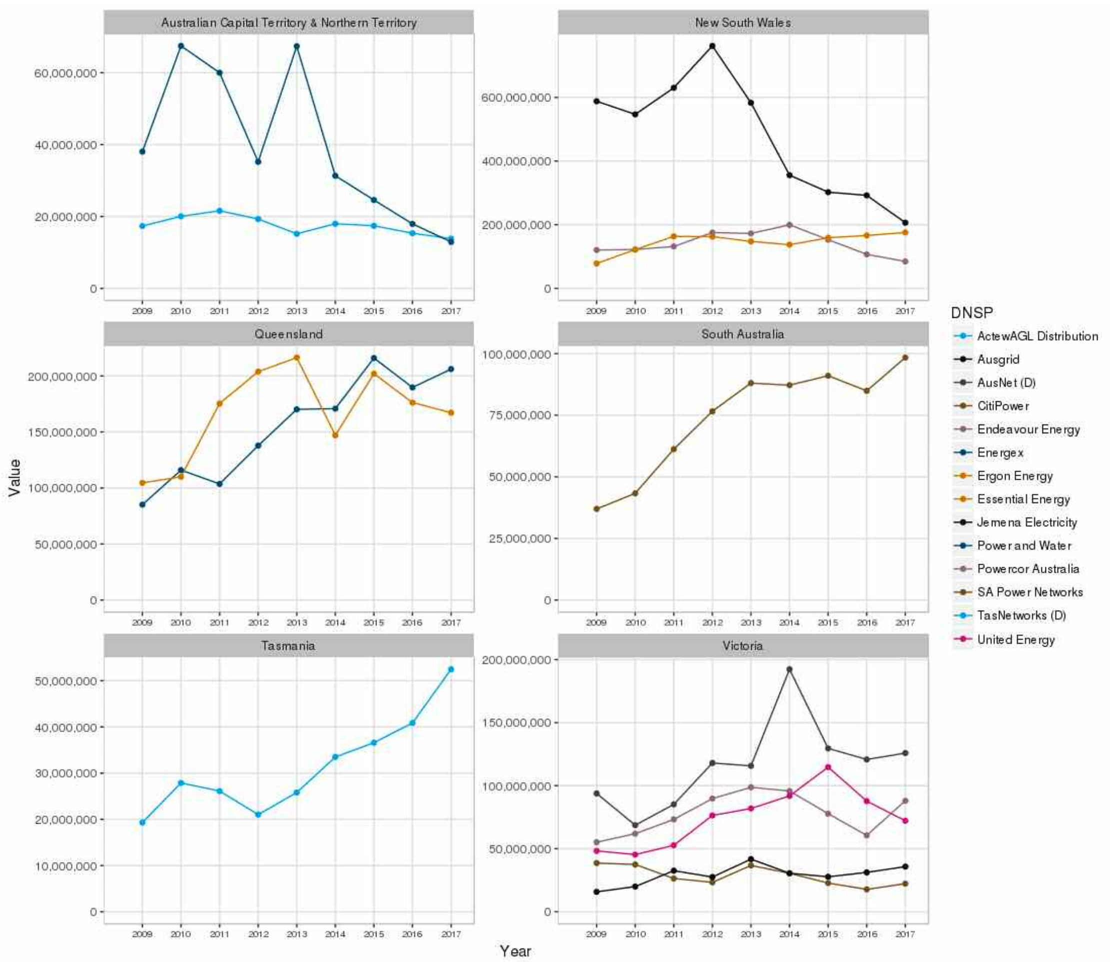
Figure 3.8 shows the replacement expenditure trend for each distribution NSP. It is interesting to note that Augrid's replacement expenditure trend closely resembles its capex trend unlike some of the other distribution NSPs. The ACT saw a relatively stable level of replacement expenditure with minor fluctuations, whereas the NT saw significant variations in expenditure. South Australia Power Networks and TasNetworks have seen a positive trend in replacement expenditure over the reporting period. Queensland distribution NSPs reported an increasing trend in replacement expenditure in contrast to their augmentation expenditure. A declining overall capex in recent years for Queensland indicates that the reduction in augmentation expenditure may have been higher than the increase in replacement expenditure. Victorian distribution NSPs have reported a relatively stable level of replacement expenditure with a slight decline in recent years.

Figure 3.7: Combined distribution NSP replacement expenditure NEM



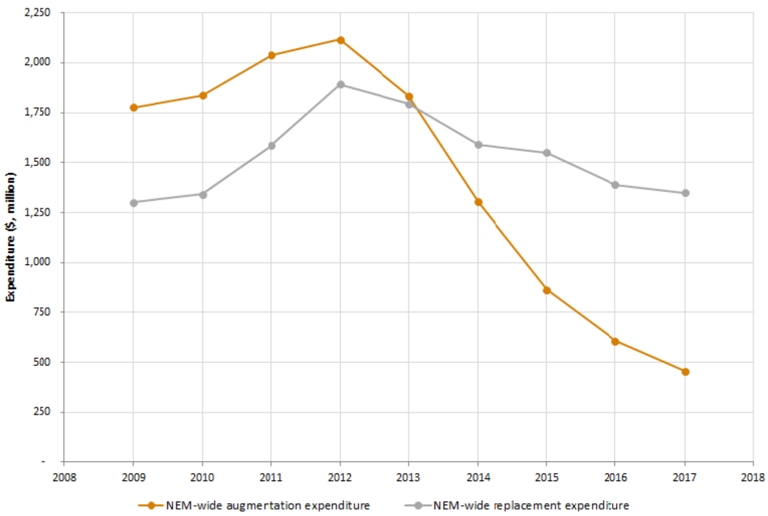
Source: AER
Note: values in 2017 real dollar terms.

Figure 3.8: Distribution NSP replacement expenditure



Source: AER
Note: values in 2017 real dollar terms.

Figure 3.9: NEM distribution NSP replacement - augmentation expenditure comparison



Source: AER
Note: values in 2017 real dollar terms.

Figure 3.9 compares the level of combined augmentation and replacement expenditure across the NEM. It can be seen that since 2012-13 the level of replacement expenditure in NEM has been higher than the level augmentation expenditure, indicating that since that point asset replacement investment has outstripped investment for expansion, almost by a ratio of 3:1 in the most recent reporting cycle. It can also be seen that during peak augmentation expenditure years the augmentation expenditure level was higher than the replacement expenditure.

In 2017, the Commission made the replacement expenditure planning arrangements rule change to improve the transparency of retirement, de-rating and replacement decisions by electricity network service providers and to make those decisions subject to the regulatory investment test for the first time.[85] The impact of this rule change will be monitored in the future versions of the ENERF review.

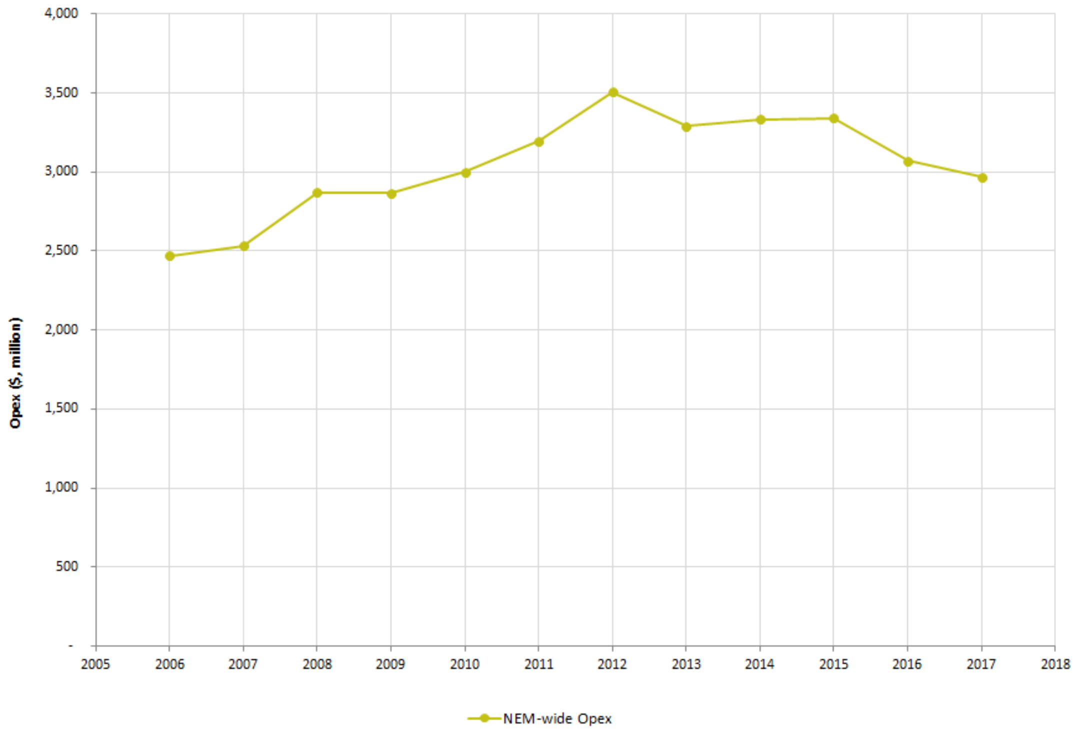
3.1.3 Distribution NSP Opex

Operating expenditure (opex) refers to the operating, maintenance and other non-capital expenses incurred in the provision of network services. As shown in figure 3.10, the combined distribution NSP opex in the NEM saw a general trend of steady increase until 2014-15 but since then the trajectory of opex has seen a change. The last two years have seen reductions in the reported opex. The efficiency benchmarking carried out by the AER since 2014 may have contributed to this reduction. The benchmarking is focused on

85 AEMC, Final rule: *Replacement expenditure planning arrangements*, July 2017.

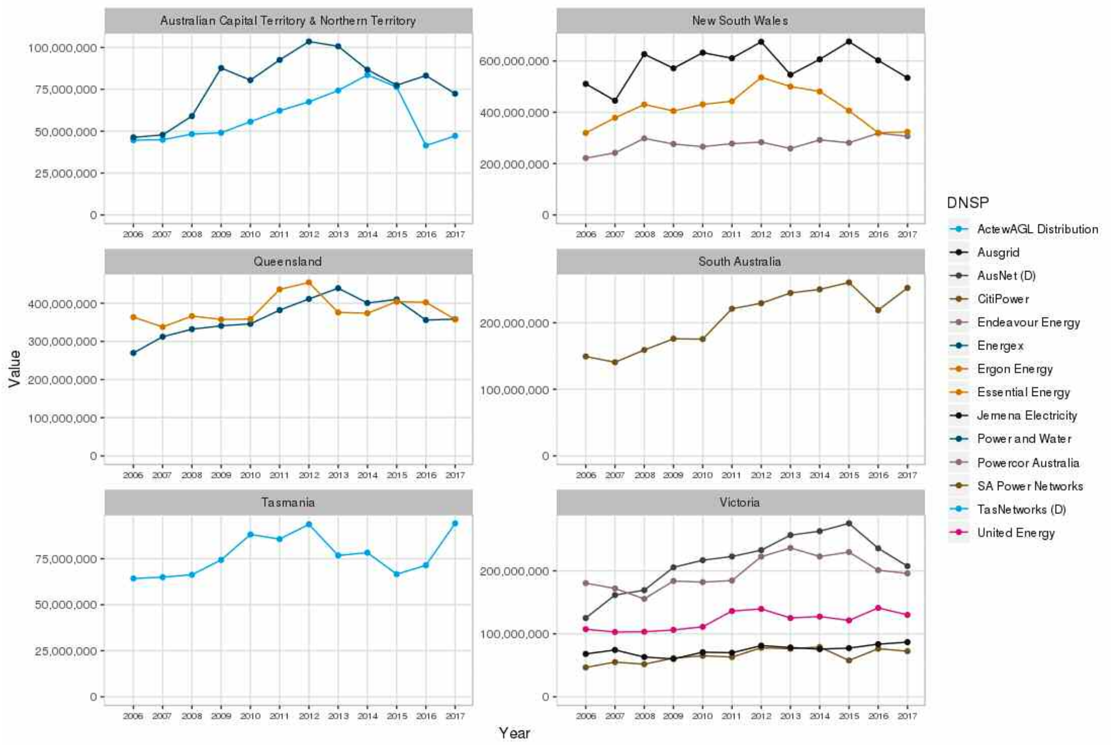
examining the relative efficiency of the distribution NSPs in providing services over a 12 month period. The rules require the AER to carry out efficiency benchmarking and have regard to benchmarking when determining efficient expenditure allowances.

Figure 3.10: Combined distribution NSP Opex NEM



Source: AER
Note: values in 2017 real dollar terms

Figure 3.11: Distribution NSP Opex

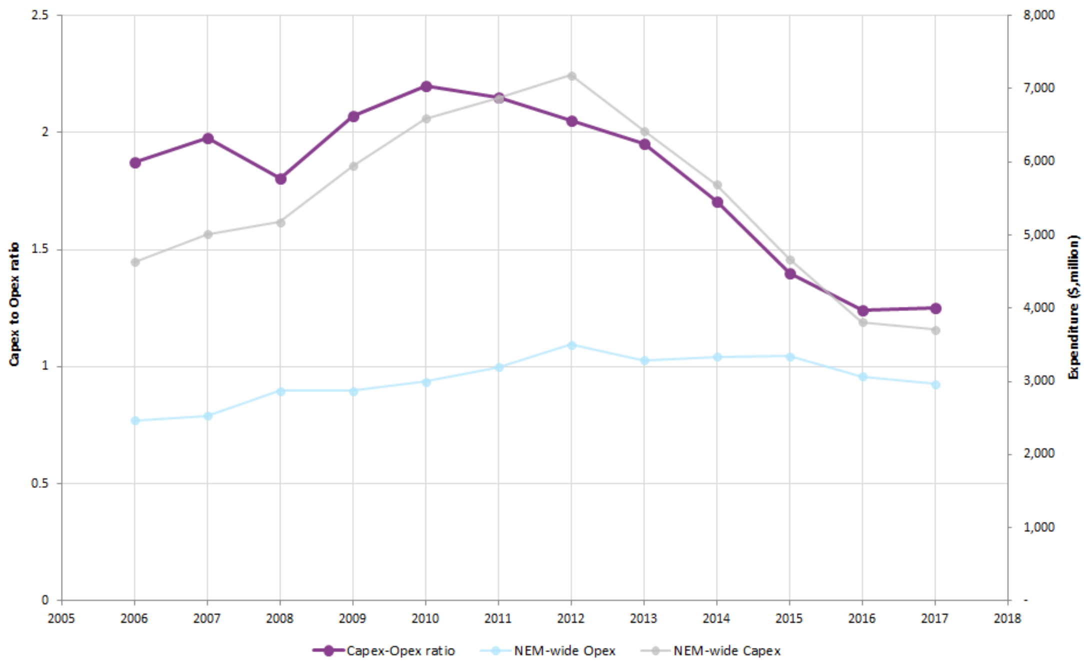


Source: AER
Note: values in 2017 real dollar terms

Figure 3.11 outlines the operating expenditure (opex) for each distribution NSP for the past several years. A general trend towards a reduction in opex in recent years can be seen for distribution NSPs in QLD, NSW and Victoria. Some of the NSW based distribution NSPs including Ausgrid and Essential Energy seem to have made significant gains in opex reduction in recent years, although from high initial levels of opex. South Australia and Tasmanian distribution NSPs have seen an increase in their opex in recent years.

Figure 3.12 below compares the combined NEM capex to opex over the past several years. The combined annual capex to opex ratio over the reporting period saw some initial volatility followed by a decrease in the ratio from 2009-10 until 2016-17. A minor increase in the capex to opex ratio was reported in 2016-17. The reduction in the ratio is likely to be primarily driven by the trend of decline in capex as the opex has remained relatively stable over the reported years. In the recent years, the capex to opex ratio has stabilised at approximately 1.25.

Figure 3.12: Combined distribution NSP capex - opex ratio for NEM



Source: AER
Note: values in 2017 real dollar terms

3.2 Trends for transmission NSPs

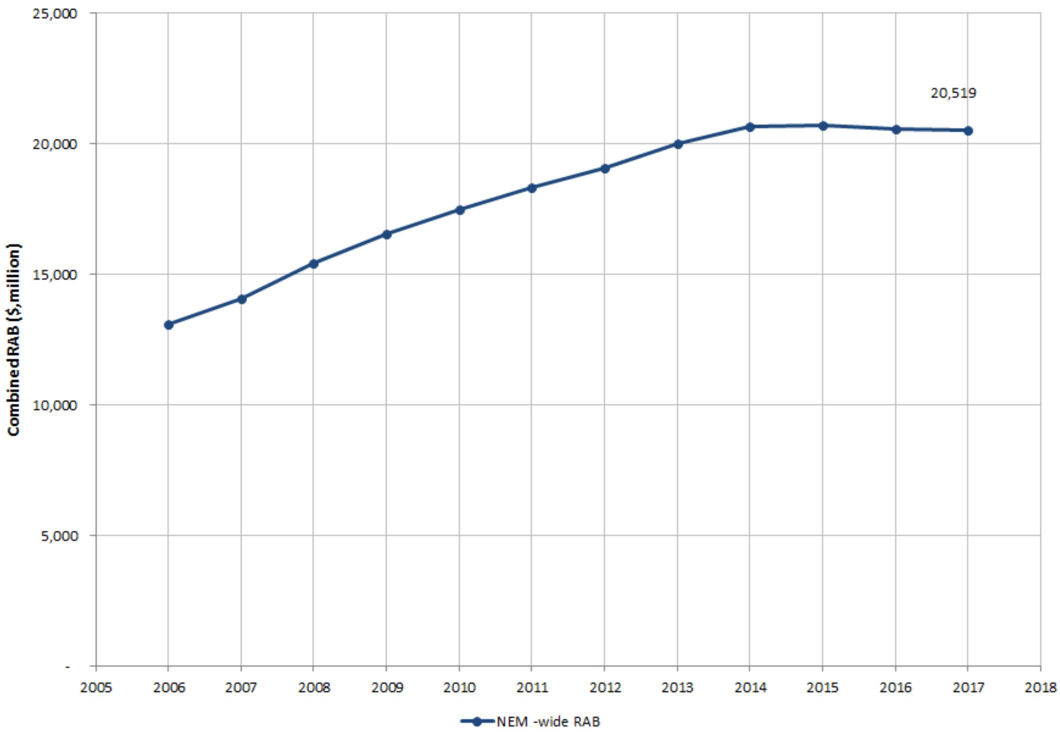
In this section some of the key market metrics for transmission NSPs are explored. The discussion is limited to the key investment metrics of RAB and Capex.

3.2.1 Transmission NSP RAB

Figure 3.13 shows the combined closing RAB for all transmission NSPs in the NEM.[86] It can be seen that trend in transmission NSP RAB is quite similar to that observed at the NEM level for the distribution NSPs. The transmission NSP RAB saw growth until 2014/15 and the trend in transmission NSP RABs has plateaued over the last few years.

86 Please note that there are differences in RIN reporting times between jurisdictions. AusNet report submits its reporting in March of each year whereas TNSPs 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 2016-17 financial year is represented as 2016 data for the NEM wide analysis.

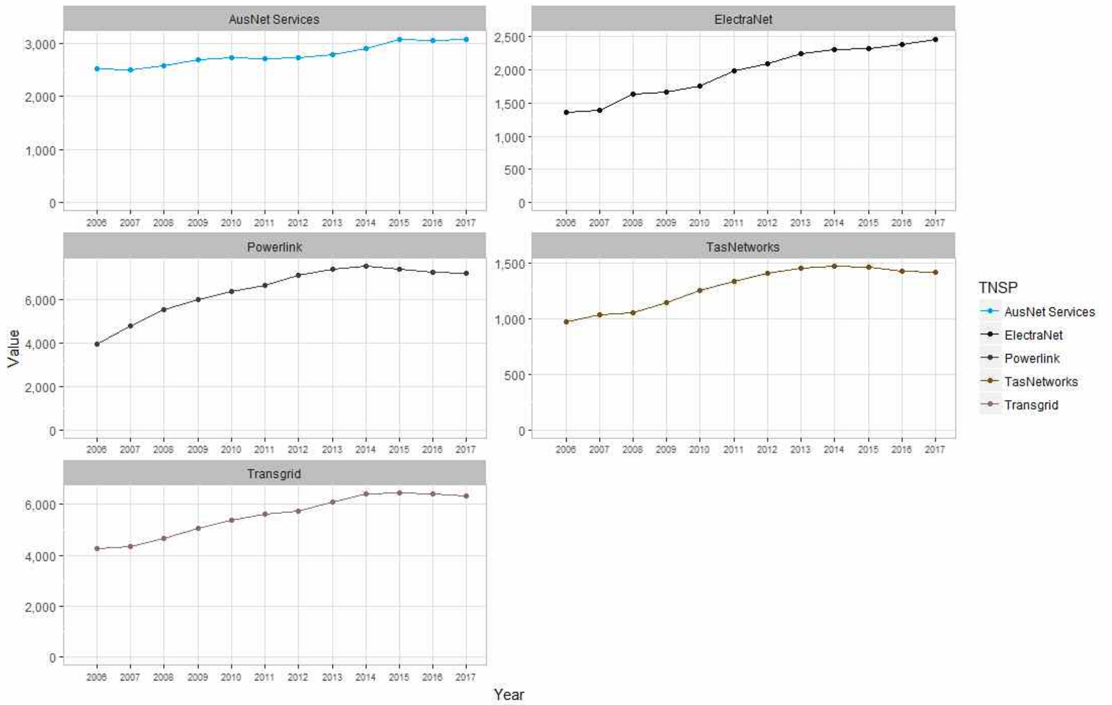
Figure 3.13: Combined transmission NSP RAB in NEM



Source: AER
Note: values in 2017 real dollar terms

Figure 3.14 shows the RAB for each transmission NSP. It can be seen that the RAB trends for Powerlink, Tasnetworks and TransGrid closely align to the trend seen across NEM, with flatlining growth in recent years. This is likely because these transmission NSPs combined make up a large share of the RAB across the NEM and hence have a greater potential to drive the NEM wide RAB trend. It can also be seen that RAB for ElectraNet has continued to grow in recent years.

Figure 3.14: Transmission NSP RAB

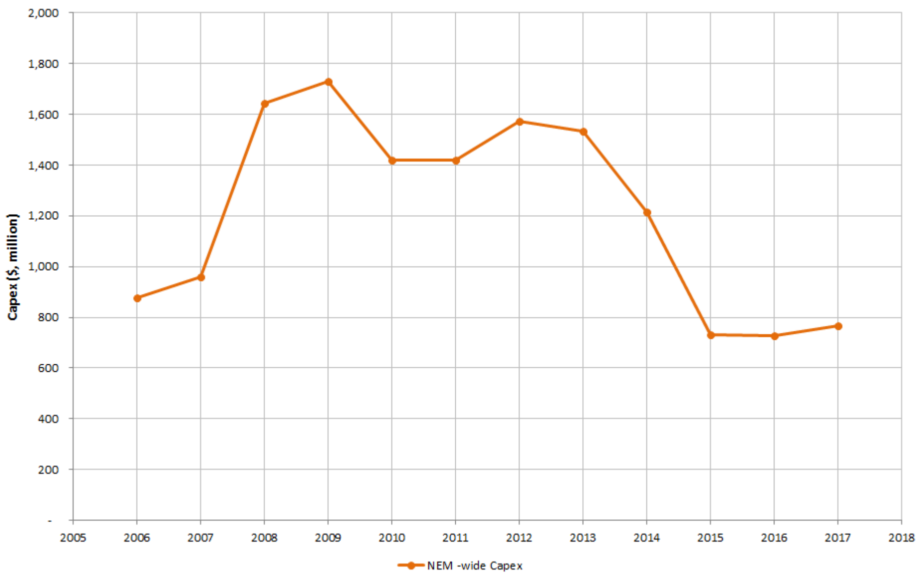


Source: AER
Note: values in 2017 real dollar terms

3.2.2 Transmission NSP Capex

Figure 3.15 shows the combined annual transmission NSP capex across the NEM. It can be seen that the capex across the NEM has seen fluctuations over the reporting period. The capex levels reported over the last few years have been relatively low. This is likely related to the plateauing of the combined transmission NSP RAB that has been observed at the aggregate level.

Figure 3.15: Combined transmission NSP Capex in NEM

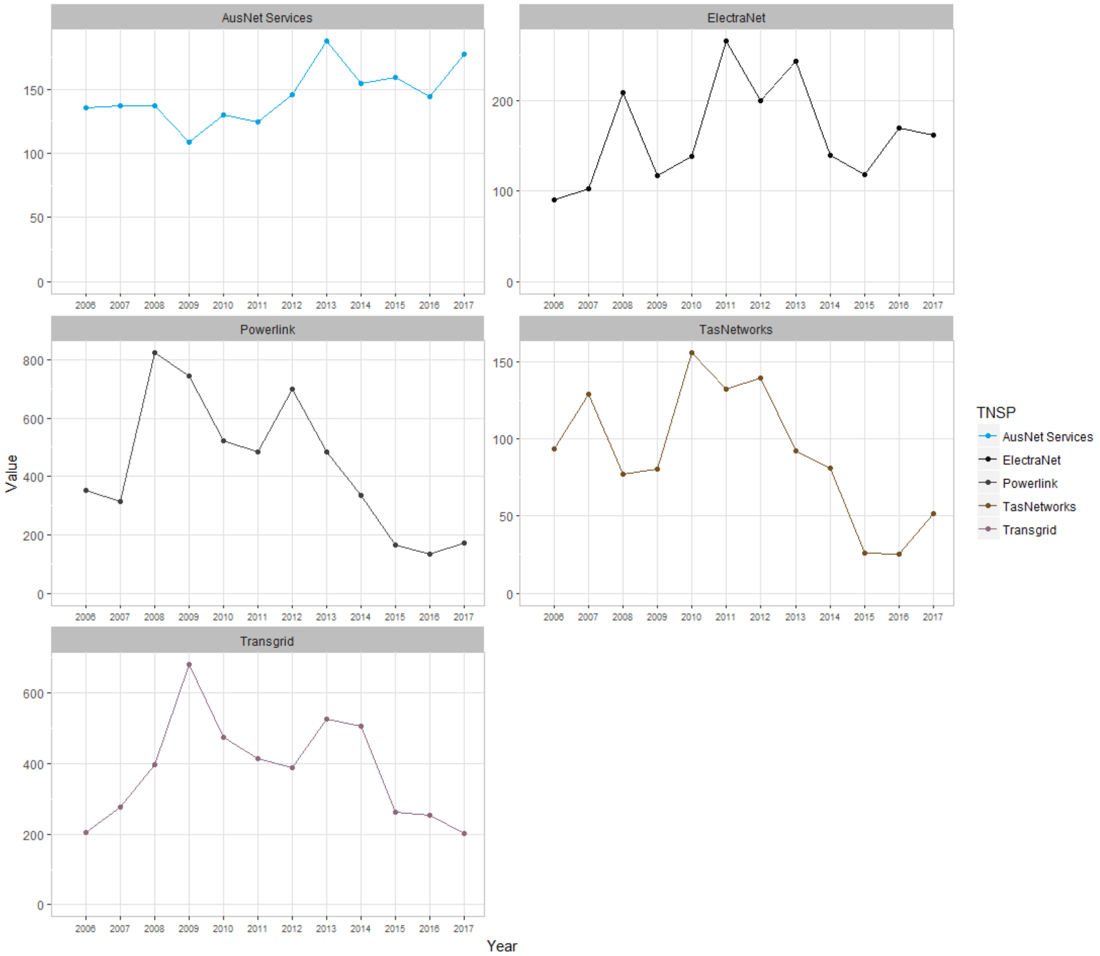


Source: AER
Note: values in 2017 real dollar terms

Figure 3.16 shows the capex for transmission NSPs observed over the past several years. It can be seen that the capex by Powerlink and TransGrid was lumpy with some years having noticeably higher levels than other. This is the main driver of the lumpy combined capex trend observed at the NEM level.

Over the recent years, a strong trend of reduction in capex across several transmission NSPs, including Powerlink, TransGrid and TasNetworks has also been observed. The reduction in capex is particularly pronounced for Powerlink. It can also be seen that the AusNet has defied the trend of recent reduction, and has recorded a general trend of moderate increase in capex. ElectraNet has seen a significant level of volatility in annual capex.

Figure 3.16: Transmission NSP Capex



Source: AER
Note: values in 2017 real dollar terms

3.3 Conclusion

The NEM saw a significant level of distribution NSP RAB growth until 2014-15 but since then the distribution NSP RAB level has plateaued. Over the last few years, the combined distribution NSP RAB has been stable at approximately $70 billion. The plateauing RAB level is largely driven by a sharp decline in capex since 2012-13 onwards, with the lowest level of capex in 10 years being recorded in the latest year of reporting, and a particularly large fall in augmentation expenditure. The level of replacement expenditure has been relatively stable over the reported years. The impacts of the new replacement expenditure rules introduced in 2017 will be monitored in the future versions of this review. The combined distribution NSP operational expenditure saw a steady rise over the early part of the reporting cycles but its trajectory has seen a decrease over the last two reported years, largely attributable to efficiency benchmarking carried out by the AER since 2014. A similar trend in the combined RAB value of the transmission NSPs has been observed with the values increasing until 2013-14 and then levelling off at approximately $20 billion. The combined capex saw lumpy increases in the first few reported years followed by years of decline to reach a lower steady level.

Some commentators consider that there has been an over-investment in network infrastructure and have called for the write down of the value of network RABs. The Commission considers that more targeted measures such as extending the AER's power to conduct ex-post reviews of the efficiency of capital expenditure of the immediate past regulatory period provides a better measure to manage the risk of overinvestment in the future. The Commission will consider this reform as part of the 2019 review.

One of the drivers of capex and RAB growth during the past decade was changes made by the New South Wales and Queensland governments to distribution reliability standards in relation to a series of outages in those states. These changes drove significant increases in investment by the distribution NSPs in those states over a period of several years.

In 2013, the Commission completed reviews of the arrangements for setting distribution and transmission reliability standards across the NEM. In those reviews, the Commission recommended a new framework for determining levels of reliability in distribution and transmission networks so that they reflect the needs of customers. Compared with current arrangements for setting reliability standards, the Commission's recommended framework would promote greater efficiency, transparency and community consultation in how reliability levels are set across the NEM.

The Commission's recommendations from those reviews have not been adopted by the Council of Australian Governments (COAG) Energy Council to date, although the New South Wales Government requested the new South Wales Independent Pricing and Regulatory Tribunal (IPART) to apply aspects of the Commission's recommended model when setting transmission reliability standards. The Commission recommends that the COAG Energy Council give further consideration to reforming how distribution reliability standards are set and applying the Commission's recommended framework in light of the changing role of NSPs.

4 OPPORTUNITIES AND CHALLENGES CREATED BY DER UPTAKE

Summary of key observations

- The increasing uptake of distributed energy resources (DER) in the national electricity market (NEM) present opportunities for the power system to become more efficient as the DER can be capable of providing an array of services to a range of parties.
- However, the continued uptake of uncoordinated passive DER can also present technical challenges to the distribution networks and system security.
- Some of the services provided by the DER are well established such as self-consumption of rooftop photovoltaic (PV) generation by households, while some of the emerging services are currently being trialled and tested by stakeholders.
- DER vary in terms of their sophistication levels and can be broadly categorised as either 'passive' or 'active' depending on their capability to respond to market signals, with most of the DER capacity installed so far falling in the passive category.
- As DER becomes more sophisticated, the market is also seeing the procurement of an array of DER services by third parties, including for wholesale and network services.
- Higher penetration of DER is causing technical issues in some parts of the network, which are increasingly experiencing voltage related quality of supply issues.
- If there is no ability to control solar PV output into the grid, there may also be other system security challenges in the future.
- With these network and system challenges on the horizon, consideration needs to be given to how to coordinate DER, and the role distribution network service providers (NSPs) will have in enabling this coordination.

As outlined in chapter 1, DER technologies are developing in sophistication and rapidly dropping in cost. New business models are also emerging in response to the value offered by these technologies, with the number of virtual power plants (VPPs) and small generation aggregators in the market increasing.

DER, if well managed, present opportunities for the power system to become more efficient. However, without the correct coordination of these resources, continued installation of DER can present operational challenges and potentially increase costs in other parts of the system.

This chapter considers the:

- capabilities of DER and the opportunities these create to realise different value streams
- technical challenges that DER can pose to distribution networks and system security.

4.1 Opportunities created by DER

4.1.1 Capabilities of DER

The uptake of DER presents opportunities for several parties to be able to benefit from an array of services that can be provided by DER. This was recognised in the Commission's *Distribution Market Model* (DMM) report and Energy Networks Australia and CSIRO's *Network Transformation Roadmap*.[87] DER have a range of technical capabilities, that at the highest level can be grouped into three categories, namely energy, reactive power and reserves.[88] These capabilities allow DER to offer multiple services that can be valuable for consumers, retailers, energy service providers, the Australian Energy Market Operator (AEMO) and network businesses. Although some parties have been utilising the services offered by DER, there is the potential for a wider range of parties to be able to draw greater benefit from an array of services.

As highlighted in the Commission's DMM report, some of the benefits may include:

- **Customer services:** Consumers may use DER to reduce their energy costs by 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. Consumers are also expressing an increasing desire to 'trade' the energy they generate with others, otherwise known as peer-to-peer trading.
- **Network services:** NSPs may procure the services provided by DER to help them provide common distribution or transmission services, such as by reducing peak load in order to defer network augmentation, or to help manage the technical characteristics of their networks.
- **Wholesale services:** Electricity retailers, energy service companies or aggregators may use the electricity generated and/or consumed by DER in aggregate to manage their risk of participating in the NEM, or for actual participation as a generator in the NEM. Parties may also use DER to provide ancillary services, such as frequency control ancillary services, to AEMO.

Although the DER can provide several services, not all of these can be provided by one particular DER at the same time. For example a battery connected at the distribution level cannot be used simultaneously to alleviate network congestion, which involves the battery discharging, and to provide a lowering FCAS service, which would require the battery to charge to absorb power. Therefore the party controlling the resource is required to make trade-offs between the services that can be provided by the resource at any point in time. Optimisation services manage these multiple trade-offs to maximise value from the DER. Several trials are underway that aim to explore and demonstrate the benefits provided by DER in commercial settings.[89]

87 ENA and CSIRO, *Electricity network transformation roadmap: final report*, April 2017.

88 ENA and CSIRO, *Electricity network transformation roadmap: future market platforms and network optimisation*, 2017, P.35.

89 Examples include: Salisbury trial by SAPN, CONSORT trial at Bruny Island and AGL's virtual power plant trial.

4.1.2 Sophistication levels of DER

DER vary in terms of their sophistication levels and can be broadly categorised as either 'passive' or 'active'. An example of passive DER includes rooftop solar PV which export to the grid when generating and are not controlled to respond to price signals. Most of the DER capacity installed to date is passive rooftop PV generation whose output is determined by weather conditions rather than the party controlling the resource.

Active systems involve generation, battery storage or demand management installations that are capable of remote signalling and control which allows them to be orchestrated by the party controlling the resource or through automated response to incentives. Batteries coupled with smart controls capable of responding to the market signal in a complex manner can be categorised as active. The Commission expects that, over time, active DER will become more widespread as standards continue to be updated, if incentives or obligations to do so exist and if the cost of doing so is not prohibitive.[90]

Passive DER systems can only provide a narrow range of services. These include self-consumption and passive export services to the grid. Active DER on the other hand can be capable of providing an array of services including FCAS services. This is discussed further below.

4.1.3 Realisation of the different DER value streams

The array of services that can be provided by DER differ in terms of their maturity. Some of these services are well established, while others are emerging services and there is potential for additional services to emerge in the future. The feasibility of some of the emerging services is currently being trialled and tested by some stakeholders. The market is also starting to see the procurement of some DER services by participants.

The capabilities of DER such as rooftop PV to provide the following services to consumers are well established:

- self-consumption
- passive exports
- reduced consumption from the grid.

These benefits have led to the strong uptake of rooftop PV by households over the last decade, as discussed in section 1.2. The uptake was largely driven by bill reduction through self-consumption and passive exports of PV generation. It was also highlighted that the perception of reduced reliance on the grid also motivates some consumers towards DER uptake. Because of these benefits, consumers are expected to continue their uptake of DER.

Moving from passive to active DER, and particularly battery storage systems, provides potential to derive more value for customers, networks and power systems system from DER. The potential network services that can be provided by DER are reasonably well understood.[91] The ENA and CSIRO *Electricity network transformation roadmap* estimated that

90 We note that Australian Standard 4777.2:2015 prescribes mandatory and voluntary demand response and power quality response modes for all inverters installed after October 2016.

91 ENA and CSIRO, *Electricity network transformation roadmap: future market platforms and network optimisation*, 2017, P.41.

$16 billion in network infrastructure investment can be avoided by the orchestration of distributed energy resources by 2050.[92]

The roadmap highlighted that without appropriate incentives or orchestration, increased passive DER could drive additional network investments with associated costs to consumers. However, though improved incentives and orchestration there is a real opportunity to unlock further value from DER investment by harnessing potential services such as peak demand management, local power quality management and reduced network investment.[93]

Several services that can be potentially provided by the DER are currently being explored by different parties.

For example, according to United Energy (UE), solar and storage provides an opportunity to deliver a more incremental capacity approach to network planning[94] and UE is undertaking the residential solar and storage systems project to explore the use of solar and battery storage systems to defer network augmentation. The project is aimed at validating the ability of solar PV and storage technology to defer or eliminate the requirement for traditional network augmentation.[95]

Controllable solar and battery storage systems can allow UE to reduce peak demand by better aligning consumer consumption and production. Where peak demand is growing and approaching the network capacity limits, solar and storage can be progressively installed on the network to delay a capital investment in augmentation until a clear trend and peak demand growth is evident and it is established that network augmentation is required to support customer load. Where peak demand continues to grow, solar and storage can be incrementally added to provide additional capacity where it is cost effective in relation to traditional augmentation.[96] The Commission's understanding of this approach is depicted in figure 4.1.

UE estimated that should the battery prices fall according to the forecasts, DER solutions would be a cost effective alternative for distribution substation and low-voltage circuit upgrades on its network by 2025. The Commission notes that initiatives such as the *demand management incentive scheme* and *demand management innovation allowance* should also encourage distribution NSP uptake of such non-network solutions.

92 ENA and CSIRO, *Electricity network transformation roadmap: final report*, April 2017, p.40.

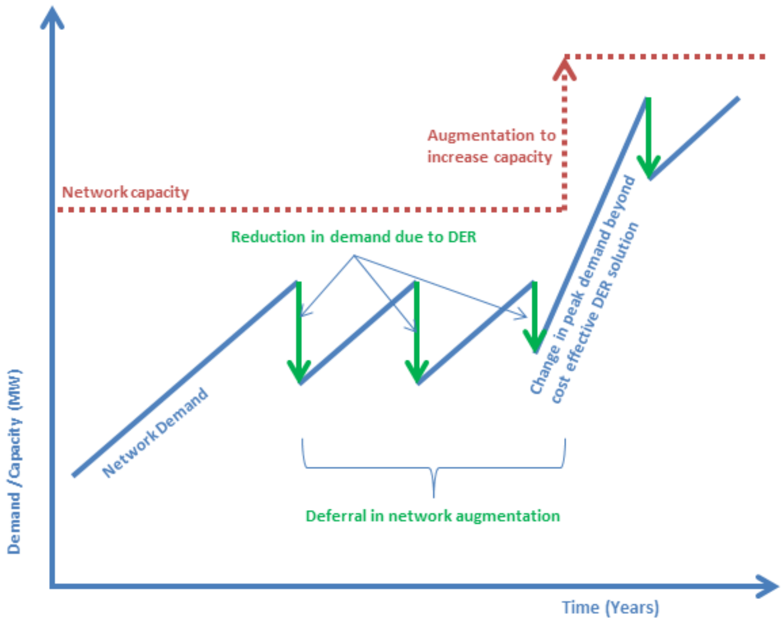
93 ENA and CSIRO, *Electricity network transformation roadmap: final report*, April 2017, pp.40-41.

94 United Energy, *ARENA Knowledge sharing plan – Residential Solar and Storage Program interim report*, February 2018, p.6.

95 United Energy, *ARENA Knowledge sharing plan – Residential Solar and Storage Program interim report*, February 2018, p.7.

96 United Energy, *ARENA Knowledge sharing plan – Residential Solar and Storage Program interim report*, February 2018, p.6.

Figure 4.1: How DER may assist in network augmentation deferral



Source: AEMC

Case study: United Energy residential solar and storage systems project

The following steps were carried out by UE to demonstrate DER capability in deferring investment.

UE identified several constrained substation assets where solar and storage solutions were more economically viable than the traditional augmentation solutions. UE identified 14 substations that formed part of the trial and established that a total of 42 DER systems were needed to be installed to bring substations to their design ratings and be effectively equivalent to a network augmentation.

Potential customers were recruited to be part of the trail and have DER systems installed on their premises. By 15 December 2017, 27 system installations were made and each of them included a 4 kW PV system, 9.8 kWh battery, 5 kW inverter and a Reposit power control box.

UE orchestrated the units as an aggregated fleet for network benefits (shaving customer demand and exporting to the network) on peak demand days with ambient temperature higher than 35°C. On all other times, UE orchestrated the units to maximise the financial benefit to the customer.

Preliminary results have shown that solar and storage systems can successfully manage network demand and can be a viable solution once the product matures along with lower energy storage prices. The project allowed UE to halt growth in demand and defer network augmentation across the selected constrained substation.

The constrained substation had 5 DER systems installed. The dispatch from the DER units achieved a 7% reduction in demand. As the network demand is growing at 1%, the reduction in demand achieved by DER will in effect defer augmentation for 7 years.

The results also showed that centralised control of batteries can provide network support without materially reducing the primary customer benefit of bill reduction through solar PV shifting. The project has also shown the potential for residential batteries to mitigate emerging challenges such as maintaining network reliability, quality, and security of supply as the penetration of solar PV continues to increase.

Source: United Energy, *ARENA Knowledge sharing plan – Residential Solar and Storage Program interim report*, February 2018, p.17.

4.1.4 Unlocking of the value stack to bring greater benefits

As some parties explore and demonstrate the benefits of DER services, the market is also seeing the procurement of an array of DER services by other parties, including for wholesale and network services.

The Commission considers that it is more efficient and appropriate for networks to procure services provided by DER from third parties (or from the network business' ring-fenced affiliate), rather than to install and own batteries at a customer's premises that are only used to provide network services. Network procurement of DER services in this manner will better enable the unlocking of multiple value-streams from DER installations. Following the Commission's contestability of energy services final determination in 2017, such an approach will be required by NSPs instead of projects where the DER are owned by a distribution NSP.

The market is seeing aggregators use the combined capabilities of consumers' DER to participate in the NEM.[97] Examples include programs such as Gridcredits by Reposit Power, which involves consumers allowing their retailers to draw power from their battery storage during price spike events. Similarly, distribution NSPs are starting to procure services from consumers' batteries, sometimes via an aggregator, to help manage peak demand. Examples include the Mornington Peninsula community grid project, where United Energy will make use of DER to manage network constraints.[98]

At present, the type of emerging DER services being procured are highly bespoke and negotiated on a case by case basis.[99] This means that consumers' DER is currently providing only a few of the value streams that it is capable of. In the future, enablers are expected to allow DER to provide an even wider range of services. This would allow the consumers to

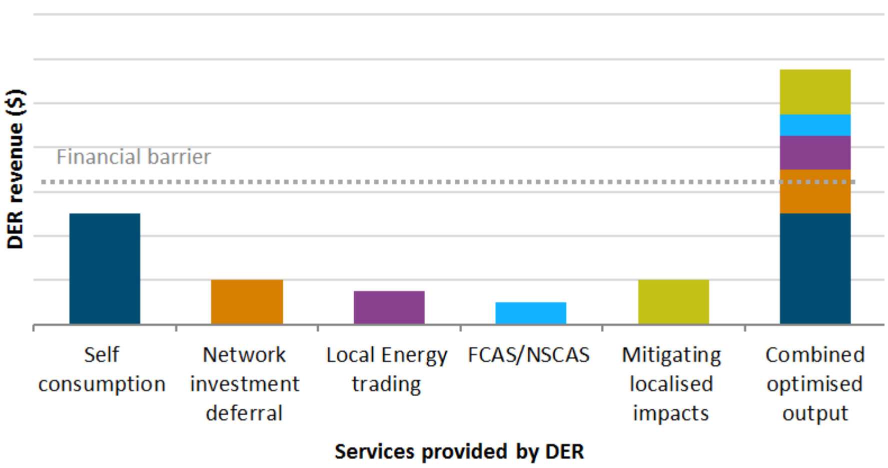
97 This is an example of DER providing wholesale services.

98 UE will be procuring DER services through the Greensync's Dex platform.

99 AEMO and ENA, *Open Energy Networks*, June 2018, p.22

"stack the value" from multiple revenue stream and unlock the potential of their DER. This is also likely to make investment in DER more attractive to consumers. Figure 4.2 below depicts the concept of "stacking the value" to increase the DER revenue.

Figure 4.2: Stacking the value concept



Source: AEMC
Note: This is a stylised chart intended to illustrate the concept and is not intended to be representative of the value of any of the DER services.

In the future, with growing experience and usage, some DER services are likely to become more standardised and potential dynamic markets for DER services could develop.[100] This could allow consumers to bid their DER capacity into a dynamic market and also allow purchasers of these services such as a distribution NSP to procure these services in a much more flexible way.

Optimisation services and the coordination of DER are the other enablers that are expected to help maximise the value of investments in DER. As DER cannot provide all of the services at the same time, optimisation services are expected to give consumers the ability to maximise the benefits of an investment in DER by enabling them to, if they choose, receive the maximum possible benefit of utilising and selling the full range of services that the distributed energy resource is capable of providing.[101] The aggregation and coordination of DER may also facilitate services being provided to market participants at both the distribution and transmission level. Coordination may also be required to manage the challenges caused by the increasing penetration and utilisation of DER that are discussed in the next chapter.

4.2 Challenges posed by uncoordinated passive DER uptake

The uptake of DER also presents several challenges to the electricity system, which was originally designed to deliver power from centralised large scale generators to consumers

100 AEMO and ENA, *Open Energy Networks*, June 2018, p.15.
101 Subject to any operational limitations such as network constraints.

rather than to integrate consumer owned distributed generators. At low levels of penetration, DER can be, and have been, accommodated within Australia's distribution networks with limited impacts. This is because networks generally have had spare hosting capacity and so possessed some ability to be able to adapt to the impacts of DER such as voltage rise. However, distribution networks are likely to be increasingly affected by DER as penetration levels increase. The widespread uptake of DER is also expected to pose system-wide challenges.

4.2.1 Technical challenges for networks

The network businesses are required to operate the distribution networks within specified technical limits, and the increasing penetration of passive DER can make it more challenging to maintain the network within these limits. Low levels of DER penetration does not have a major impact on the operation of the networks. However, the distribution networks have a limited hosting capacity for passive DER, beyond which further passive DER penetration cannot be managed without breaching one or more of the technical limits or expanding network capacity. There are a range of technical issues that can be caused by increasing uncontrolled DER penetrations which include power quality issues, power safety issues and system security issues.[102]

The nature and magnitude of these technical impacts will differ between locations.[103] Relevant factors include the customer density, topology, technical characteristics and the level of uptake of DER. Other factors, such as jurisdiction specific technical requirements and distribution NSP set standards may also have an impact. The penetration of the rooftop PV capacity varies, with South Australia and Queensland having higher penetration than other regions. As a result, some distribution networks will experience greater susceptibility to these technical impacts and so will need to adapt to accommodate a higher penetration of DER more quickly than others.

4.2.2 Network challenges being faced today

Some of the technical issues that can be caused by DER are currently being faced in parts of some networks. As highlighted in section 1.2, some states have seen a higher uptake of passive rooftop solar PV, with more than 30% of households in Queensland and South Australia having installed rooftop PV systems. As a result, parts of the distribution network in these regions have significantly higher levels of solar PV penetration and are beginning to see:

- **Voltage issues:** This can include poor voltage regulation, voltage fluctuations and voltage unbalance. Some of the impacts of over voltages can include damage to both consumers' and networks' equipment. DER such as solar PV and battery storage will

102 See Box 2.1 in the *Distribution Market Model* final report for a description of the range of technical impacts that DER can cause, including voltage issues, thermal overloading, harmonic distortion, high levels of flicker, low power factor and reduced fault currents. View at: https://www.aemc.gov.au/sites/default/files/content/fcde7ff0-bf70-4d3f-bb09-610ecb59556b/Final-distribution-market-model-report-v2.PDF.

103 The KPMG report for the Australian Energy Council also noted this: network impacts are unlikely to be uniform - both in time and magnitude - across all distribution networks. See: KPMG, *Distribution Market Models: Preliminary Assessment of Supporting Frameworks, Report for the Australian Energy Council, June 2017*, p. ix.

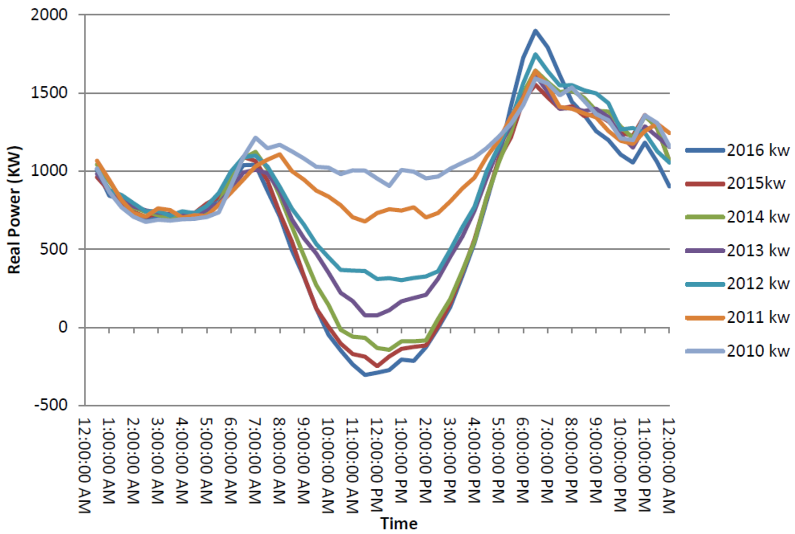
generally trip off to prevent over voltage, however this can lead to the the voltage dropping and the process repeating itself. The resulting voltage fluctuations can exceed the standards for flicker, and excessive flicker can lead to poor customer experience and customer equipment mal-operating.

- **Thermal overloading:** If a feeder has DER installed, surplus generation is fed back to the grid during times of high generation and low load. This reverse power flow may exceed the equipment thermal ratings.

In areas with high penetration, the effects of high rooftop PV generation on load profiles are starting to become evident. Distribution feeders designed for one way power flows are starting to experience reverse power flows due to high solar PV generation during the middle of the day in some areas.

Figure 4.3 below shows the daily load pattern for a residential feeder in Burrum in Queensland over seven consecutive years for the first week in September. It can be seen that the load profile of this feeder has been significantly impacted by increasing generation from rooftop PV to the point where it experiences reverse power flow. The peak demand for this feeder is still occurring at the same time of the night, but the mid-day demand has reduced by over by over 1 MW and the daily variance has increased from 0.8 MW to 2.2 MW. This increase in daily variance makes it more challenging to manage the network voltage and can also result in decreased asset life of some network components.[104]

Figure 4.3: Burrum Heads Feeder - changes in load profile



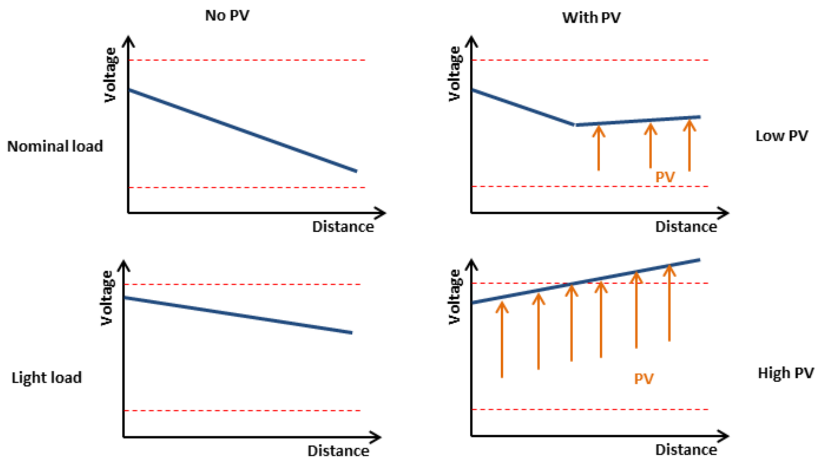
Source: Ergon Energy, Distribution annual planning report, September 2017, p.29.

104 Ergon Energy, *Distribution Annual Planning Report,* September 2017, p.29.

Energex reported that approximately 10% of its 11kV feeders are experiencing reverse power flows during some times of the year.[105] Energex expects that this number will continue to increase with the addition of solar PV on the network.

The increasing generation from rooftop PV is resulting in distribution NSPs having to manage voltage rise issues caused by solar PV generation. Distribution NSPs are required to supply voltage to end customers within a tolerance range established under jurisdictional regulations.[106] Operating beyond this range would render distribution NSPs in breach of their quality of service requirements. The export of excess generation by solar PV onto the distribution network causes voltage to rise on the network. If the amount of solar generation being exported is high enough when the local load is low, this can cause the voltage in the network to increase to a point beyond the tolerance range, particularly in weaker parts of the distribution networks. Figure 4.4 depicts how rooftop PV can cause the voltage in a distribution network to rise.

Figure 4.4: Voltage rise due to increased rooftop PV generation



Source: AEMC

Box. 4.3 sets out a case study summarising some of the challenges that were encountered by AusNet in the township of Yackandandah located more than 30 km from the nearest Zone-Substation.

Case study: Totally Renewable Yackandandah (TRY)

In an effort reduce greenhouse emissions and become 100% renewable by 2022, the community of Yackandandah in country Victoria established a volunteer run community

105 Energex, *2017 DAPR*, November 2017, p.86.

106 For example, see: Department of Industry Resources and Energy, *Code of Practice: Electricity Service Standards*, August 2015.

group, which they named Totally Renewable Yackandandah (TRY). In late 2016, TRY established a partnership with MondoTM Power to develop one of Australia's first commercially operated mini-grids in Yackandandah.

Prior to the TRY mini-grid, more than 30% of homes in Yackandandah had solar systems, which is already double the average take-up in their distribution network. The TRY partnership agreed to pursue a mini-grid as part of realising Yackandandah's 100% renewable energy vision. As part of the mini grid, over 100 additional households established new solar systems, lifting Yackandandah's solar participation to 42% of households.

The township of Yackandandah is located in AusNet Services distribution area more than 30 km from the nearest Zone-Substation. To facilitate solar connections to the network, AusNet Services' connection process provides for online pre-approval of solar generation installation proposals from its customers not exceeding 5.0 kW capacity per phase. Though an increased penetration of solar generation connections at Yackandandah was facilitated by the TRY partnership, and collectively represents a significant solar capacity increase, AusNet Services processed the connection services applications of individual customers using its published processes.

Prior to implementing TRY's initiative, the distribution network at Yackandandah was already experiencing voltage control issues under certain operating conditions. As is the case in any distribution network area with significant solar system uptake, managing the line voltage becomes more challenging. The feed-in 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) just above the upper network voltage limit of 253V. The distribution network must be operated within the voltage limits specified in the Victorian Electricity Distribution Code.

For solar customers, this can create a self-defeating situation, when solar density reaches a point where voltage instability causes their systems to automatically cut out. This tends to happen when sunlight conditions are most conducive to solar generation. To manage the impact of solar power feed-in on network voltages, AusNet Services may reduce these voltages to allow more 'headroom' for solar feed-in.

Conversely, late in the day and as the sun sets, solar generation diminishes and does not contribute to the community's peak energy need. This can cause voltage levels to approach the lower regulated limit.

The voltage range that must be managed by network equipment and controls is significantly broadened by high concentrations of PV establishment. Voltage can exceed the upper network limit (253V) when solar systems are generating power, then approach the lower limit (216V) as solar output diminishes. In both cases, the impacts are greater toward the end of the network.

As a result, AusNet Services must take action to mitigate the voltage fluctuations. In the case of the TRY partnership mini-grid, applications were lodged concurrently and automatic pre-approval granted before the network implications were analysed. AusNet Services typically attempts to mitigate this by requiring new or modified solar connection to establish limited or zero export limits. More than 20 households agreed to establish zero export arrangements, and had their inverters configured accordingly.

Significant expenditure on the network has also been required. As a consequence of the extra generation capacity and the summer seasonal peak, a significant spike in voltage complaints was received, including a complaint from the local hospital. Over the summer, AusNet Services spent over $200,000 on works to strengthen the network in Yackandandah and recalibrate the High Voltage network to lower the voltage. This alleviated voltage issues for the majority of customers. However, customers at the end long lines in the vicinity of Yackandandah may now be subject to lower than permitted voltages.

AusNet Services is actively investigating alternatives to these augmentation works through orchestration of DER and adjusting the switching times for controlled loads. If successful, network augmentation works could be avoided.

Notwithstanding the above initiatives, further works on the network are likely to still be required to mitigate the voltage issues. This may be modest, depending on the success achieved through non-augmentation initiatives, but if reconductoring of feeder sections or installing new voltage regulators becomes necessary this would incur a high cost, and more than has been spent to date.

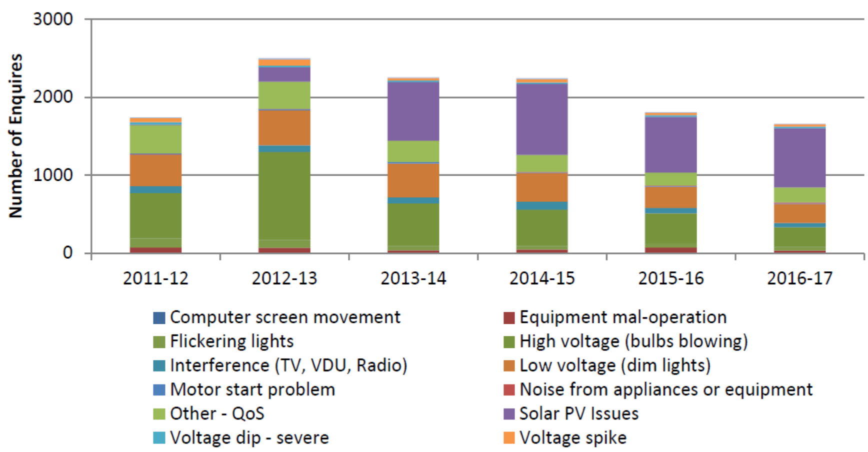
Through consultation with distribution NSPs, the Commission understands that for some of the distribution networks, there is limited monitoring equipment on the low voltage (LV) parts of the distribution networks, therefore the current magnitude of technical issues caused by high uptake of passive DER is not clear.

However, many distribution NSPs are experiencing quality of supply (Qos) complaints caused by rooftop PV. Figure 4.5 shows the quality of supply complaints received by Ergon Energy over a six year period. It can be seen that quality of supply complaints relating to solar PV, mainly due voltage rise issues, have become increasingly prominent over the last few years and is now the biggest source of Qos complaints for Ergon Energy. In the year 2016-17, solar PV enquiries formed the largest proportion of Qos enquiries for Ergon Energy, Energex and South Australia Power Network, accounting for 38%, 45.8% and 29.6% of the total Qos enquiries received by the respective distribution NSP.[107] Ergon Energy managed approximately 670 Qos complaints relating to solar PV.[108]

107 Energex, *2017 DAPR*, p.130, November 2017; South Australia Power Network, *Distribution Annual Planning Report*, December 2017, p.80; Ergon Energy, *Distribution Annual Planning Report*, September 2017, p.132.

108 Ergon Energy, *Distribution Annual Planning Report*, p.28, September 2017.

Figure 4.5: Ergon Energy quality of supply complaints



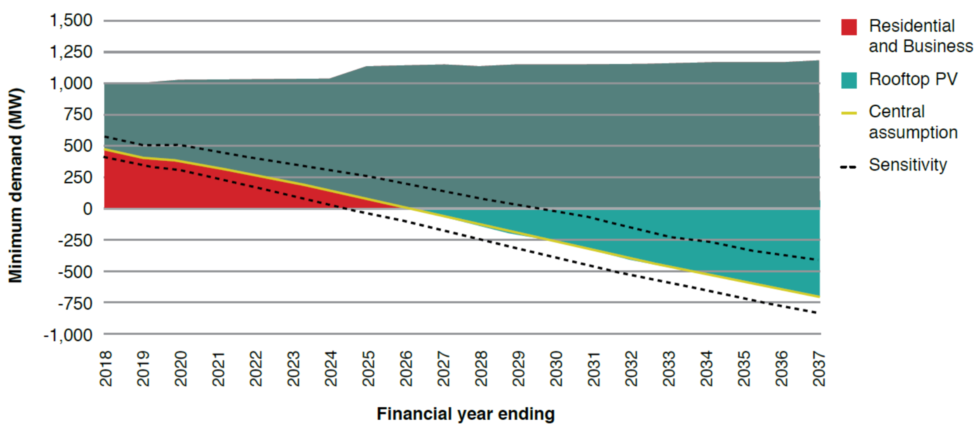
Source: Ergon Energy, Distribution annual planning report, September 2017, p.141.

4.2.3 System security and reliability challenges

DER can also affect power system security and reliability at the transmission and distribution level, and demand patterns at the wholesale level. The high uptake of rooftop PV alongside the broader transition of the generation mix is predicted to pose system-wide challenges such as frequency control issues and challenges for load forecasting.

These challenges associated with DER are projected to manifest first in those states with high levels of controllable rooftop PV generation such as South Australia. As shown in figure 4.6, on minimum demand days in South Australia, rooftop PV is forecast to provide all demand by approximately 2025.

Figure 4.6: AEMO minimum demand forecast for South Australia



Source: AEMO and ENA, *Open Energy Networks*

In addition, as noted in the ENA-AEMO consultation paper, given the broader transition in the market, if there is no ability to control solar PV output, there may be other system security challenges.[109] According to the consultation paper, it may become necessary to curtail non-scheduled generation. Managing the flows of the interconnectors and operating the system within secure limits are also expected to become progressively challenging in South Australia.[110]

Higher levels of DER penetration can also make load forecasting more challenging for AEMO if the DER penetration is not visible. AEMO noted that historically, load forecasting has relied on the underlying diversity of consumer behaviour, which means that not all appliances are used at the same time in the same ways. Those that are used at the same time, for example air conditioners, are correlated to weather patterns and so can often be predicted.

However, AEMO notes that some DER are either undiversified (e.g. rooftop PV which, in a particular region all just generate because the sun is shining, or all do not generate due to it being cloudy or night-time) or less predictable in how they operate (e.g. batteries controlled by algorithms set by energy service providers), which can, in aggregate, offset the underlying diversity in consumer demand, change the daily load profile and make load forecasting more challenging.[111]

DER in aggregate controlled through a VPP can also pose challenges to the local network, as well as the system as a whole.[112] The capacity of VPPs has the potential to rival that of a scheduled generator. The prospect of virtual power plants responding to wholesale price signals raises questions of whether they should be involved in the central dispatch process in order to reduce the extent of any distortions they impose on the market.[113] For example, they are capable of ramping their output up or down in a very short period of time and their operation can be hard for the system operator to predict, which can lead to escalating demand forecast errors and could also lead to increased need for FCAS. Another challenge for networks arising from aggregated DER is that VPPs often involve individual DER distributed across different parts of the network that may be subject to differing network constraints. The constraints can vary across time and location, and can be volatile in nature.

The Commission has an extensive security and reliability work program that is currently addressing these issues, as set out in the security and reliability action plan on the AEMC website.[114]

With these network and system challenges on the horizon, consideration needs to be given to how to coordinate DER, and the role distribution NSPs will have in enabling this coordination. The following chapter outlines potential strategies for managing DER and issues for

109 AEMO and ENA, *Open Energy Networks*, June 2018, p.15.

110 Ibid.

111 AEMO, *Visibility of distributed energy resources*, January 2017.;AEMO, S*ubmission to reliability frameworks review directions paper,* May 2018; AEMO, *Operational and market challenges to reliability and security in the NEM*, March 2018.

112 AEMC, Draft report : *Frequency control frameworks review*, March 2018, p.26.

113 AEMC, Draft report : *Frequency control frameworks review*, March 2018, p.26.

114 See: https://www.aemc.gov.au/sites/default/files/2018-04/Security%20and%20reliability%20action%20plan_2.pdf

consideration in shifting distribution NSPs towards a more active role in understanding and managing network constraints.

5 TOWARDS NETWORK TRANSFORMATION

Summary of key observations and findings

Increasing penetration of distributed energy resources (DER) on the grid will need to be managed to avoid network and system security issues. There are also opportunities for networks to take actions to enable DER to provide more value to customers.

Network tariff reform plays an important role. Cost reflective network pricing will support the continual transformation of the sector and promote more efficient usage and investment decisions by consumers. In particular, network tariff reform will provide investment signals to DER providers and help unlock the DER value stack by assisting consumers to optimise their energy usage.

Networks have a range of potential strategies they could utilise to manage the technical challenges arising from high levels of DER. Potential options include restricting DER connections or significantly augmenting the capacity of networks, but neither of these approaches is likely to be in the long term interests of consumers. A more efficient solution is likely to be for a range of static and dynamic strategies to be implemented to manage risks and to integrate DER and network operations that maximise value, to the extent that future technological developments make this approach feasible. Further work on assessing the costs and benefits of developing capabilities to dynamically manage DER will be required, and the Commission is working with Australian Energy Market Operator (AEMO) and the Energy Networks Australia (ENA) on these issues.

The Commission considers that there may be a number of first steps that distributed network service providers (distribution NSP) can take now. The key first steps involve distribution NSPs continuing to build a better understanding of the impacts of connecting higher levels of DER to their networks and the network constraints that may emerge as a result. This is likely to involve extending current network modelling and monitoring capabilities into low voltage (LV) networks to quantify and publicise the DER hosting capacity of their networks based on factors including thermal, voltage control, power quality and relay protection limits. These capabilities will also provide the foundation for near-real time constraint management and, if shown to be required, enable the more sophisticated management and orchestration of DER to progressively release more value from DER.

The incentive-based economic regulatory framework does not prevent networks from making the technical and commercial decisions to take these first steps. However, a point may come where there will be value in establishing regulatory arrangements for the allocation of functions and responsibilities for distribution level optimisation and dispatch.

The Commission will continue to progress the discussion already underway on the future roles of NSPs. In particular, the Commission will work closely with AEMO and ENA through their consultation on frameworks to manage system operations and optimise DER. The Commission is also working with AEMO to develop a joint work program on DER with the objective of better coordinating the various areas of work that the Commission and AEMO are currently undertaking on a range of DER-related issues.

As the energy system transforms with increasing penetration of DER and growth in the connection of renewable energy at the transmission level, consideration may be required as to whether the national electricity market's open access framework remains appropriate. However, the Commission currently considers that the open access regulatory framework is appropriate as it is not preventing any of the short-term measures that need to be taken by the networks to allow effective integration of DER into the NEM.

Under an open access framework, generators (including small customers with DER) do not pay charges for use of the network but also do not receive guaranteed access to use the network and may face constraints. An open access model at the distribution level also appears to be most conducive to encouraging competitive development of DER in the future and maintains consistency with the open access framework at the transmission level.

However, this conclusion with respect to retaining an open access framework in the NEM may need to be reviewed when clearer positions are reached on the detailed mechanisms for integrating DER into the NEM, and the Commission's work on transmission access arrangements is completed.

5.1 Introduction

The networks in place today were designed for large synchronous generators and one-way electricity flow, not for high penetrations of DER and multi-directional power flows. To date, distribution NSPs have only required limited visibility of, and ability to communicate with, their networks and devices connected to them in order to maintain quality, reliability and security of supply.

As highlighted in Chapter 4, some of the technical issues that can be caused by DER are currently being faced by parts of the network. This gives an indication of the issues that are likely to become more widespread through the NEM in coming years.

AEMO has also identified the forecast uptake of DER in South Australia will pose challenges over the next decade to system security during "emergency conditions" (bushfires, severe weather, network outages), when flows on the network must be reduced to remain secure. Markets are also evolving rapidly and will bring increasing amounts of active DER onto the grid which, if unmanaged, may exceed network operation limits and also bring challenges at a system level. Active DER will need to be managed to avoid these issues.

Given these forecasts and expected challenges, the sector is at a decision point as to the role of NSP in efficiently integrating DER into the grid at least cost to customers and unlocking the value of this DER to the system for the benefit of all customers. At such a decision point, the Commission considers a vision for the role of NSPs will be valuable in informing the regulatory framework, market bodies and NSPs so that progress can be made towards network transformation even when the future is uncertain.

In particular, the Commission considers there is value in clearly articulating a desired set of outcomes that distribution NSPs are expected to deliver to customers. NSPs need to understand what is expected of them and have clear incentives to meet these expectations. It is clear that NSPs will need to transform in response to disruption in technology and markets that is underway so that they can play a role in the efficient integration of DER and other new technologies. NSPs will also need to take charge of their own future and determine the most efficient means of delivering these outcomes. The incentive based economic regulatory framework in the NEM empowers networks to do this.

The Energy Market Transformation Project Team which reports to the Council of Australian Governments (COAG) Senior Committee of Officials has undertaken to examine whether articulating a vision for the future role of electricity networks could support the current work of government, market bodies and DNSPs in respect of future network operation, investment and regulation.[115]

Distribution NSPs will continue to play a role in delivering safe, secure and reliable electricity to customers. However, the Commission envisions that the role of distribution NSPs into the future will also include better quantifying and managing constraints in Low Voltage (LV) networks in order to:

- support efficient investment in DER by customers and other parties
- unlock the value of DER to the system while maintaining quality, reliability, and security of supply
- in the future, further maximising the value of divers DER services through real time DER optimisation and dispatch functions.

Given the uncertainties of future trends, the Commission considers it useful to map out the strategies and potential changes required to move towards a more active role for DNSPs and distribution markets.

The remainder of this chapter provides an overview of the key anticipated changes in the way distribution networks will need to be managed and operated in response to changes in customer preferences and the uptake of DER including:

- static strategies that could be developed to improve incentives for DER investment and operations, including cost-reflective network tariffs which can support efficient integration of DER into the grid and performance and connection standards
- an assessment of whether the current access, connections charging, and network pricing frameworks remain fit for purpose in the context of these potential pathways for integrating passive DER and orchestrating active DER
- an overview of the work being undertaken by AEMO, other market bodies, ENA, DNSPs, market participants and technology providers on potential pathways for integrating

115 Senior Committee of Officials, *Bulletin: Optimising Network Incentive Report*, 18 April, 2018, http://www.coagenergycouncil.gov.au/publications/optimising-network-incentives-report

passive DER and orchestrating active DER with objective of maximising the value of DER to the system while maintaining quality, reliability, and security of supply

- the Commission's views on the critical first steps that distribution NSPs may take in relation to better understanding their networks to allow them to operate their networks efficiently with high levels of DER.

5.2 Static strategies to facilitate the efficient integration of DER

There are a number of static strategies distribution NSPs can use to facilitate the efficient integration of DER into the grid which can be implemented immediately, and in parallel to longer term strategies that are set out below. This section considers three specific static strategies distribution NSPs can use to address economic and technical issues that arise with the increasing uptake of DER:

- implementing cost-reflective tariffs to reduce network demand at peak times and encourage flexible load to shift to times of minimum network demand when DER generation is at its peak
- utilising the connection process and standards to address risks to the security and safety of the power system
- power quality management strategies.

5.2.1 Cost-reflective network tariffs

As DER penetration increases, including rooftop solar PV, batteries and electric vehicles, usage of the distribution network will increasingly change. Cost-reflective tariffs will play an important role in incentivising flexible demand to use the network efficiently so as to keep costs lower for all customers.

NSPs have found that solar PV has not significantly reduced peak load on the network, rather it has mainly moved the peak to later in the day, from the afternoon to later at night. Cost-reflective tariffs, such as a demand tariff, which includes a demand charge based on a resident's maximum demand during a pre-defined peak period, can incentivise customers to shift some of their consumption to off-peak periods.

Network tariffs can also be used to encourage customers to shift their usage from times of peak demand on the network to times when high solar PV output typically occurs. For example, South Australia Power Networks (SAPN) has a type of 'solar soak tariff', making its controlled load (hot water) tariff available between 10:00am and 3:00pm when solar generation is generally at highest.[116]

Cost reflective tariffs will also avoid placing a higher proportional cost on those who still rely solely on electricity from the grid. For example, where a customer with solar PV uses the same capacity on the network as a customer without solar, these two customers would pay the same amount under a cost-reflective demand tariff even if the two consumed different total amounts of electricity.

116 SAPN, *Network tariff & negotiated services*, Manual No.18, November 2017, https://www.sapowernetworks.com.au/public/download.jsp?id=68500

Cost-reflective network tariffs can also enable the development of innovative new products such as home energy management systems and automated demand response products that allow consumers to benefit from reducing peak demand without individual consumers needing to be actively engaged in monitoring and adjusting their energy usage.

5.2.2 Connection arrangements

Connection arrangements have a role in addressing some of the risks that DER poses to the quality, reliability and security of the power system. As the National Electricity Rules are not highly prescriptive regarding the technical aspects of connections under Chapter 5A (aside from any technical requirements prescribed or required by way of jurisdictional or other legislation and statutory instruments[117]), a significant amount of discretion on the technical requirements of a DER lies with the distribution NSP. It is important that distribution NSPs have this discretion in the connection process to address network constraints, without using them to create inappropriate barriers to the development of active DER markets.

Some distribution NSPs have modified their connection requirements under their connection agreements for small scale embedded generation to help manage the power quality issues. SAPN has specified that all new PV installations from 1 December 2017 must apply a power quality response mode (Reactive power control Volt-VAr response in accordance with AS-4777[118]) to their inverter (via a setting adjustment), with the Queensland based DNSPs also requiring PV inverters to provide reactive power control.[119] Ergon Energy, SAPN and Energex also limit the export capability of rooftop PV system to below 5 KW on a single phase.[120]

Ergon Energy and Energex have also introduced partial and minimal export connections for small scale generators. Minimal export connections do not permit export of generation to the grid while partial export connections allow export capabilities less than the rated output capacity of the inverter. These options allow many of the connection applications to be fast tracked, with Ergon Energy not requiring a full technical assessment to be conducted for systems below 3.5 kVA.

Energy Networks Australia (ENA) is currently undertaking a review of DNSP connection arrangements.[121] The review is being undertaken following on from recommendations made in the ENA/CSIRO Electricity network transformation roadmap, and the Finkel review. The Commission supports this work and is on its steering committee.

That Commission also recommended in its Frequency control frameworks review draft report that ENA, in developing its national connection guidelines, provide guidance on:

- what capability is reasonable to require from DER as a condition of connection in order to address the impact of that connection

117 NER clause 5A.B.2(b)(7)(iii)

118 AS4777 specifies output reduction above 250V and trip off at 260V.

119 SAPN, *Technical Standard Small: Inverter Energy Systems*, p.6, November 2017, Energex and Ergon Energy, Connection standard, Micro Embedded Generating Units, Jun 2017, p.8.

120 Ergon Energy, *Partial export option to boost solar PV uptake*, December 2016, https://www.ergon.com.au/about- us/news-hub/media-releases/regions/general/partial-export- option-to-boost-solar-pv-uptake, accessed 21 May 2018.

121 For more information see: http://www.energynetworks.com.au/sites/default/files/13122017_plug_and_play_on_the_way_for_renewable_connections_mr_0.pdf

- the expected application of AS 4777 to different connection types and sizes
- the technical justification for any mandated services
- the extent to which any mandated services would detract from the ability for distributed energy resources to offer system security services.

The ENA project provides an opportunity to develop consistent and transparent and transparency connection requirements for DER. The Commission encourages stakeholders to provide input into the development of these guidelines.

The NER sets out detailed access standards for registered generators that connect under chapter 5 of the NER (ie generators over 5MW). On 31 May 2018, the Commission published its draft determination on the generator technical performance standards rule change, based on a rule change request from AEMO. This draft determination sets out proposed changes to the way levels of technical performance are set for registered generators connecting under Chapter 5. The draft rule recognises that a changing energy mix is creating new challenges for the efficient management of the power system in a secure state. In particular, the ability to effectively control frequency and voltage on the power system is diminishing as synchronous generating systems exit the market and new asynchronous generating systems and DER enter the market.

There are currently no equivalent standards for small-scale DER that connects to the distribution network under Chapter 5A of the NER. As small-scale DER penetration increases, it may be necessary to consider whether the NER should contain a similar access standards framework for connections under Chapter 5A to provide a clearer negotiating framework for the technical standards that are included in distribution NSPs' connection agreements.

5.2.3 Power quality management strategies

There are a range of low cost power quality management strategies distribution NSPs are using to manage voltage rise issues in their network.

For example Energex's operating initiatives include company initiated investigations for solar issues, rebalancing of the LV phase connections and resetting of distribution transformer taps.[122] Energex's capital program includes enhanced monitoring of the LV parts of the network to improve visibility as well rectification works involving uprating and reconfiguring of LV network elements.[123] A recent initiative by Energex involves extending monitoring from the LV distribution transformer terminals to the end of LV circuits and within customer switchboards. Based on the monitoring data and predictive models developed, Energex identifies and prioritises areas for power quality improvement.[124]

Similarly, SAPN has also commenced a program installing metering in the LV parts of the network with high solar PV penetration to provide greater visibility of power quality issues and enable a more proactive remediation approach.[125]

122 Energex, *2017 DAPR,* November 2017, p.150.

123 Ibid.

124 Ibid, p. 155

125 SAPN, *Distribution Annual Planning Report*, December 2017, p. 81.

In its final regulatory determination, the AER allocated Energex and Ergon Energy $24 million and $26 million capital expenditure respectively to manage voltage rise and maintain power quality for the 2015-20 regulatory control period.[126] Ergon Energy and Energex advised the Queensland Department of Energy and Water Supply that their actual cost to manage the voltage rise issue in the next regulatory control period would be approximately $50 and $59 million.[127]

The Queensland government has also changed voltage standards from the nominal 240V to 230V to help support solar and renewable energy targets. The lowered voltage level is expected to help Queensland DNSPs in managing the voltage rise issue and to allow an additional 960 MW of residential solar to connect to the power grid with less need for costly network upgrades.[128]

5.2.4 Limitations of static strategies

Static strategies, such as the use of cost-reflective network tariffs, can minimise the overall electricity network costs borne by consumers due to better utilisation of the network and the deferral of peak demand driven network investment. However, price signals and incentives alone will not prevent some technical issues arising at a network and system level.

For example, batteries may be programmed to charge when extreme weather events are forecast irrespective of the network tariff. Wholesale price spikes or requirements for frequency control ancillary services (FCAS) response can sometimes occur unpredictably and without warning.

The power quality management strategies described above also have limitations. These strategies are targeted at specific power quality issues and will not prevent local network issues and system security issues that arise when excess generation is exported to the grid.

Finally, a static export limit on exports is likely to be a blunt approach to addressing the impact of DER on the network. A more sophisticated approach would be to consider the introduction of dynamic constraints that can limit the amount of energy being exported, as necessitated by changes in network conditions.

Examples of more active and dynamic options are discussed in the next section.

5.3 Towards more active distribution system operation

Extensive work is already being done by distribution NSPs, market bodies, market participants and technology providers on understanding the expected challenges and opportunities DER will pose for networks and system security and on potential measures to efficiently integrate DER to the grid, including more active and dynamic options.

126 Queensland Department of Energy and Water Supply, *Decision regulatory impact statement: Queensland statutory voltage limits*, Sep 2017, p.21.

127 Queensland Department of Energy and Water Supply, *Decision regulatory impact statement: Queensland statutory voltage limits*, Sep 2017, p.21.

128 Queensland Department of Natural Resources, Mines and Energy, *New statutory voltage limits for Queensland*, https://www.dnrme.qld.gov.au/energy/initiatives/statutory-voltage-limits, accessed 21 May 2018.

The Commission noted in its *Distribution Market Model* (DMM) report that networks, in consultation with relevant stakeholders, could further explore what minimum level of control distribution NSPs need to have over DER in order to enable higher levels of DER for future distribution level markets, without compromising their regulatory obligations including reliability and quality standards.

This issue is considered in the consultation paper, *Open Energy Networks*, published on 15 June 2018.[129] This consultation paper has been prepared by AEMO and ENA and presents potential approaches to integrating DER in the National Electricity Market which aim to optimise the value of DER while managing distribution network constraints and system security.

The consultation paper also sets out several "straw man" frameworks for a Distribution System Operator (DSO) or Distribution Level Optimisation to be developed further with stakeholders. The consultation paper discusses the high level functions, roles and responsibilities required to coordinate DER optimisation within both transmission and distribution network limits and the different options proposed by the ENA and AEMO for allocating the responsibility to manage DER optimisation and dispatch.

The options put forward in the AEMO and ENA consultation paper are also currently being considered in detail by specific DNSPs such as SAPN. SAPN recently commenced consultation with stakeholders on DER integration as part of its regulatory determination process. The Commission understands that Ergon and Energex are also considering the merits of similar approaches, and some networks are carrying out trials of complex operational approaches to optimise DER outputs.

The remainder of this section sets out an overview of this work being undertaken by AEMO, the ENA and DNSPs.

5.3.1 Options for the efficient integration of passive DER in the future

As set out in Chapter 4, networks only have a limited hosting capacity[130] to accommodate DER before voltage management issues arise and local network capacity limits are reached, on distribution transformers in particular. In addition to the static strategies identified above and more sophisticated network operational techniques which do not directly involve DER itself, the Commission considers there to be three potential approaches for integrating DER to the grid while avoiding local network and system issues. These can be summarised as:

- **Restricting DER exports where hosting capacity has been reached:** Once the local hosting capacity has been reached customers would be limited to generating for their own consumption and would be unable to export onto the grid.
- **Augmenting the network to support DER:** Investing in network upgrades to support more DER, for example, by installing voltage regulators, synchronous condensors and resistor banks.

129 AEMO & ENA, *Open Energy Networks*, 15 June 2018.

130 The term "hosting capacity" refers to the amount of DERs 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.

- **Dynamic management of DER:** Implement more sophisticated strategies to manage DER output when necessary for quality, reliability and security reasons.

Prohibiting new DER systems from exporting where local hosting capacity, has been reached or imposing broad restrictions is unlikely to be efficient or to meet customer expectations. Some issues on the network will be location specific (for example, on a specific feeder), meaning global restrictions on DER are likely to prevent DER being connected or exporting in parts of the network, and at times, where there are no issues. AEMO forecasts that even by 2035, issues in South Australia caused by excess rooftop PV are likely to occur less than 10% of the time,[131] whereas a static limit would apply 100% of the time.

Amongst other issues, this approach would also raise equity issues between first movers who have connected early and those that cannot connect due to the NSP being unable to accommodate any more DER in that part of the network. The Commission notes that it would also be inconsistent with the "open access" nature of the regulatory regime, as discussed in section 5.4 below.

On the other hand, augmenting the network to increase hosting capacity so that all current and future DER face no export constraints will come at a high cost. This is a cost that all network customers, whether they have DER or not, would pay for through their network charges under the current regulatory regime. The Commission considers that this approach would also be inconsistent with the current regulatory framework, where generators do not pay network charges but in return do not have guaranteed access to export their power across the network, as discussed further below.

However, new technologies also offer solutions to these new challenges that DER pose. NSPs will also need to innovate and evolve in order to be able to meet the technical challenges posed by DER and continue to meet quality, reliability and security obligations. These same innovations required to meet these challenges can also offer new opportunities.

The AEMO and ENA consultation paper proposes that managing DER dynamically**,** which could take into account locational and temporal specific constraints, and would unlock more value from DER at a lower cost than through applying broad export limits or undertaking network upgrades.[132]

Managing DER dynamically would involve curtailing DER exports only at times and in locations where issues are predicted to arise. Dynamic management on the rare occasions when system challenges occur will enable higher penetrations of passive DER to be securely integrated to the grid and anticipate will increase the value of DER to the customer, network and the system as a whole.[133]

5.3.2 Capabilities that DNSPs require for the dynamic management of passive DER

Distribution NSPs currently have limited visibility of their LV networks. As figure 5.1 illustrates monitoring has been limited to their HV networks where Supervisory Control and Data

131 AEMO & ENA, *Open Energy Networks*, 15 June 2018, p. 17.

132 Ibid.

133 Ibid.

Acquisition (SCADA) systems are typically used. SCADA can be used for facilitating remote monitoring and coordinate, control and operate distribution components at a substation and feeder level. Previously, distribution NSPs have not required this level of visibility or automation on their low voltage networks given the one-way flow of electricity and largely predictable loads.

With the increasing uptake of DER, distribution NSPs will require increased visibility of LV networks to establish how much DER can be connected and to assess where constraints may emerge which may cause technical impacts on the network. Figure 5.1 illustrates how distribution NSPs may extend monitoring to their LV networks using a combination of LV transformers and new data sources (for example, from smart meters and DER). Further capabilities, in addition to additional LV monitoring would be required to dynamically manage passive DER.

The ENA and AEMO have identified a number of capabilities that they consider distribution NSPs will need to build in order to be able to dynamically manage passive DER:[134]

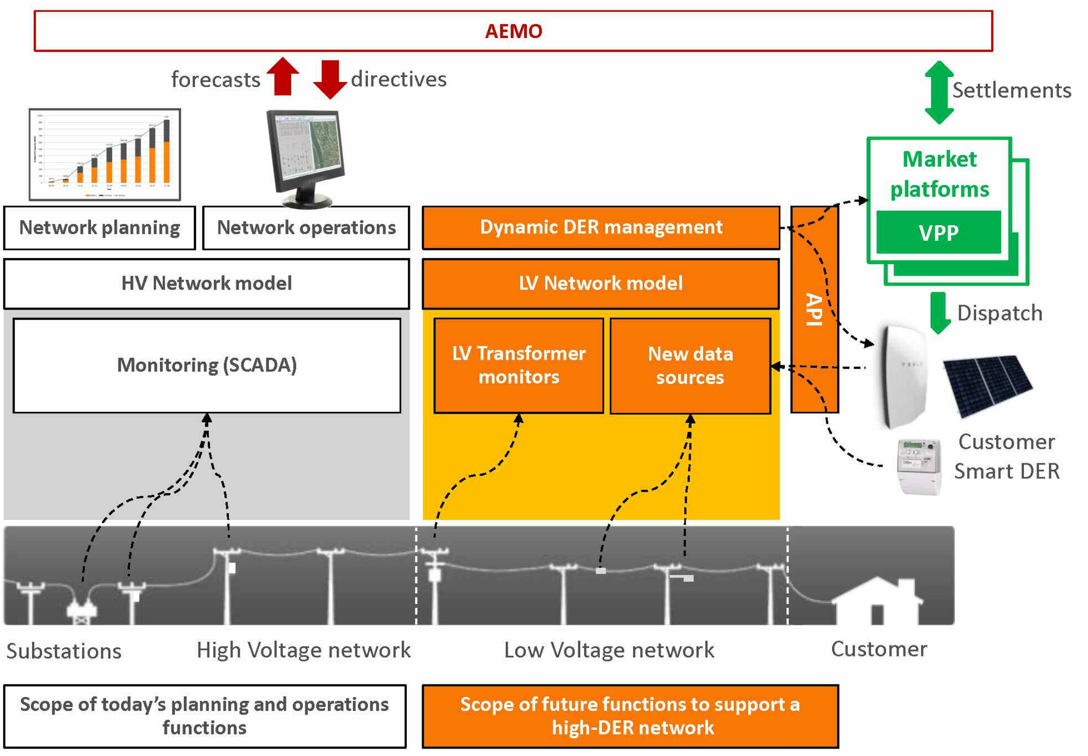
- Network modelling and monitoring: would need to be enhanced, particularly in the LV network. This would be required to quantify local hosting capacity, determine where DER management may be required and where DER-related constraint remediation may be efficient.
- Advanced planning: would be required to consider new scenarios that network planners have not needed to consider in the past such as performance under minimum demand scenarios e.g. under full or intermittent cloud cover. Planners would also need to consider the potential value of customer exports in undertaking investment decision making.
- Advanced operations: would be required to undertake management of DER where and when required.

Capabilities on the customer side would also need to be further developed with DER needing to be capable of receiving control signals from remote parties (including AEMO and networks), and be able to, as a minimum, reduce their output in times of emergency conditions.[135] This has implications for standards and connection agreements.

However, implementing advanced monitoring, planning and operational strategies will require investment by distribution NSPs. The Commission considers that it will be important that the economic and planning regulatory frameworks enable this type of expenditure if it is demonstrated that the benefits to consumers exceed the costs, so that the system can evolve to manage increased DER penetration at the least cost to customers. This is discussed below in Section 5.5.

134 Ibid, p.18.
135 Ibid.

Figure 5.1: Present and proposed capabilities



Source: SA Power Networks

5.3.3 Orchestrating active DER to manage system security and unlock the value stack

Moving from passive to active DER, including controlled PV, batteries and electric vehicles, provides the potential for more value for the customer, network and the system.

However, in order to realise the value from active DER there are a number of challenges for distribution networks and security of supply. This will occur to a large extent because of DER's unpredictability. Whereas passive DER behaviour can be forecast with reasonable certainty, particularly when diversified across large numbers of customers, wholesale price spikes or requirements for FCAS response can sometimes occur unpredictably and without warning. Active DER may respond in unpredictable ways to these sudden signals.[136]

For example, the Tesla Virtual Power Plant is proposed to reach a capacity of 250MW (charging and discharging). This VPP could ramp up to 500MW almost instantaneously, if moving from discharging to charging (or vice versa). This has a similar operational impact to

136 Ibid, p. 21.

the trip of a large power station, and exceeds the typical contingency reserves enabled in South Australia.[137]

A number of technology vendors and retailers are currently developing and testing aggregation of DER and associated market platforms and retail offers.

For example, AGL, with support from Australian Renewable Energy Agency (ARENA), is developing a VPP with 5MW of capacity in South Australia. It will consist of 1,000 distributed energy storage systems.[138] The objective of the project is to demonstrate the role of distributed energy storage in enabling higher penetrations of variable renewable energy. The project is working with SAPN to provide greater visibility of the aggregated DER as well using these resources to address local network constraints and manage demand. The virtual power plant will also utilise Greensync's deX platform.[139]

Although such platforms and offers are still at a pilot stage, the market is developing rapidly and competition appears to be sufficient to drive it forward.

In the DMM report, the Commission concluded that the increased uptake of DER is likely to require greater consideration of the value from optimising in the investment and operation of DER. Optimisation provides a way to send signals to whoever has control of the DER to provide the service that will deliver the most value to the consumer at that point in time. An optimising service would give consumers the ability to maximise the benefits of an investment in DER by enabling them to, if they choose, receive the maximum possible benefit of utilising and selling the full range of services that the DER is capable of providing, given transaction and information costs, and technical constraints. Consumers may choose to 'optimise' the operation of their DER themselves, or give this function to an agent, for example, their electricity retailer or energy service company, to optimise the resource's operation on their behalf.[140]

This includes co-optimising the operation of DER with the wholesale market. This would involve consideration of how distribution networks can, in both a technical and regulatory sense, enable the efficient use of DER in distribution markets and effective access for DER to participate in transmission-level markets, such as the wholesale market.

As discussed in Chapter 4, through the *Frequency control frameworks* review the Commission is also currently seeking to identify any barriers to DER to participating in system security frameworks, and where these barriers are unnecessary or inefficient, is considering how they could be addressed.

Functions in DER optimisation

Under the current regulatory framework, aggregators in affiliation with retailers, directly participate in the wholesale market without any mediation from distribution NSPs. Despite there being no regulatory requirements to do so, the Commission understands that

137 Ibid.

138 AGL, *Virtual power plant in South Australia – Stage 1 milestone report*, July 2017.

139 For more information on deX, see: https://greensync.com/solutions/dex/

140 AEMC, *Distribution Market Model*, final report, 22 August, 2017 p. ii.

aggregators generally work closely with distribution NSPs to understand network constraints, the opportunities to provide network support, and impacts of dispatching virtual power plants on the distribution network.

However, depending on how these arrangements evolve and the number of aggregators that enter the market, a point may come where there will be value in establishing regulatory arrangements for the allocation of functions and responsibilities for distribution level optimisation and dispatch.

The AEMO and ENA commenced a public consultation process on potential future frameworks and markets for optimising DER by outlining the high level functions, roles and responsibilities required to coordinate DER optimisation within both transmission and distribution network limits. AEMO and ENA identify the potential allocation of responsibilities for each of these functions, and indicated the majority of the functions appear to align well with existing parties. These are set out in Table 5.1 below.

Table 5.1: Summary of key functions in DER optimisation identified by AEMO and ENA

	DESCRIPTION	OWNER
1. Distribution system monitoring and planning	Enhanced function: distribution network monitoring to inform distribution network constraint development.	DNSP
2. Distribution constraints development	New function: to develop distribution network constraints that will be a key input into the distribution level optimisation.	DNSP
3. Forecasting systems	New function: provide key forecasting information to allow for distribution level optimisation – may be available to market participants.	DNSP, AEMO, or new third-Party
4. Aggregator DER bid and dispatch	New function: Aggregates local DER installations to provide bids into the energy, FCAS and Network Markets (through distributed level optimisation).	Third- Party: New participant category
5. Retailer DER bid and	Enhanced function: Retailer	Retailer

	DESCRIPTION	OWNER
dispatch	aggregates customer DER installations to provide bids into the Wholesale Market for scheduled generation, scheduled load, FCAS and Network Markets.	
6. Distribution level optimisation and dispatch	New function: optimise distributed level resource dispatch within distribution network constraints, to establish an aggregated bid stack for DER per area that can feed into wholesale optimisation. Dispatch DER once aggregated dispatch signal received.	DNSP, AEMO, or new third-Party
7. Wholesale - distributed optimisation	New function: Integrate distributed level optimisation results into existing wholesale market optimisation.	AEMO and operator of distribution level optimisation
8. Distribution Network Services	Enhanced function: Distribution network services, such as power quality/voltage control, which can be provided by aggregated DER, either through bilateral contracts or potentially through an optimisation.	DNSP
9. Financial Settlements (Network)	Enhanced function: financial settlement of distributed network services dispatched to the Network Market.	DNSP, aggregator/retailer
10. Data & Settlement (Wholesale and Frequency Control Ancillary Services [FCAS])	Enhanced function: AEMO settles wholesale and distributed level transaction. AEMO already settles the existing market to the NMI.	AEMO
11. DER Register	New function: AEMO to	AEMO

	DESCRIPTION	OWNER
	provide DER register based on AEMC rule requirements.	

Source: AEMO and ENA

The Commission considers that the first two functions of distribution system monitoring and planning and distribution constraints development are consistent with the role of distribution NSPs in providing distribution network services, and the Commission's vision for the future role of distribution NSPs and distribution networks as set out at the start of this chapter. These functions are analogous to a transmission NSP's role at the transmission level where transmission NSPs provide transmission network limit advice to AEMO which is used in AEMO's constraint equations. However, the Commission notes that it is unclear whether constraint equations could be used accurately in distribution level dispatch and distribution NSPs may need to develop and provide constraint information differently to transmission NSPs.

If the optimising function is taken on by a party who has a particular regulatory interest in the provision of a particular service (i.e. where the provision of that service has a higher value to the party who takes on the optimisation function than to what the consumer's preference would be), then that party is acting in accordance with its own interests and is unlikely to make decisions that result in the full value of that distributed energy resource being maximised.

If distribution NSPs were to undertake the role of optimising and dispatching DER across both network support markets and wholesale markets, it may exhibit bias towards services it has a financial interest i.e. the network support market. The AEMO and ENA consultation paper suggests that models for managing any potential conflicts of interest with ring-fencing could be considered to address biases.

However, as set out in the DMM report, the Commission considers that even with effective ring-fencing, market participants may still perceive there to be a conflict of interest for distribution NSPs providing optimisation services, which may affect how those parties participate in that market and lead to inefficient outcomes.[141]

In the Commission's view, the distribution level optimisation service should be provided by a party who does not have a specific interest in one or more of those services being provided, or in a particular way, and cannot exert market power or influence on the provision of those services. That is, the optimising service should be provided separately from the provision of regulated services.

AEMO and ENA outline the following three broad options for coordination of DER dispatch within distribution network limits for the purposes of consultation with stakeholders:[142]

141 AEMC, *Distribution Market Model*, final report, 22 August 2017, p. 32; KPMG in their report for the Australian Energy Council note that perception of independence will be key for market confidence.

142 AEMO & ENA, *Open Energy Networks*, 15 June 2018, pp. 29-33.

1. **AEMO optimising distribution level dispatch through a central integrated platform:** Under this option, AEMO provides a central platform that interfaces with aggregators for the provision of DER services - therefore providing direct access to the market. Each distribution NSP would also be connected to the central platform. To consider local network constraints, each distribution NSP would assess the DER bids and offers against their network constraints and provide them to AEMO in either gross form or an aggregated view per transmission connection point. AEMO would then optimise the dispatch of DER based upon those bids, as a part of the overall system optimisation in the NEM Dispatch Engine (NEMDE).
2. **Distribution NSPs optimising distribution level dispatch within their own networks:** This model involves distribution NSPs aggregating bids from all active DER in their networks, then passing these aggregated bids to AEMO associated with each transmission connection point. AEMO would calculate dispatch targets at each transmission connection point and communicate these to the distribution NSP. The distribution NSP would disaggregate these dispatch targets to each aggregator, based upon their respective bids (with the lowest priced offers having the most access to network capacity).
3. **Independent distribution system operators (iDSOs) or AEMO optimises distribution level dispatch:** In this third option, and iDSO or AEMO (an extension to AEMO's dispatch function) is required to take on the responsibility of optimising DER dispatch within distribution network technical limits. The iDSO would pass these aggregated bids to AEMO to include in the NEMDE central dispatch process. This may involve establishing a separate iDSO for each distribution network, or a single iDSO for the NEM.

The AEMO and ENA paper only discusses these potential models at a high-level, consistent with the role of the paper as a consultation document rather than a final report setting out recommended solutions. Significant details remain to be resolved following consultation. It will be important that practical approaches for the implementation of these options be developed, and until more details are available the Commission is not able to provide a view on which is the preferred model.

5.3.4 Next steps

It will be important that market bodies, NSPs and stakeholders continue to work together to monitor and resolve these issues. The Commission agrees with AEMO and the ENA that industry wide collaboration is essential during this time of transition.

The Commission will work closely with AEMO and ENA through their consultation on and provide input to their process. The Commission considers holding joint stakeholder workshops on the appropriate market design and regulatory arrangements would be valuable.

The Commission is also working with AEMO to develop a joint work program on DER with the objective of better coordinating the various areas of work that the AEMC and AEMO are currently undertaking on a range of DER-related issues. For example, the Commission is currently considering market framework issues in relation to the participation of DER in system security frameworks in the *Frequency Control Frameworks Review*.[143]

5.4 Implications for the access, connections charging, and network pricing.

The Commission has considered the implications for access arrangements of the different potential approaches to managing passive DER and enabling DER to become dispatchable. This follows on from the findings the Distribution Market Model final report in which the Commission undertook to consider the arrangements for distribution network access and connection charging for distributed energy resources in Chapters 5A and 6 of the NER as part of this review.

This section sets out:

- an overview of the current access arrangements in the NEM at the transmission and distribution level
- the Commission's views on alternative options to the existing open access framework
- the Commission's views on interactions between the access, connection charging framework and network pricing.

5.4.1 Access framework

All transmission and distribution networks in the NEM currently operate under an open access regime for the connection of generation.

It is necessary that flows of electricity across transmission and distribution networks are consistent with the networks' physical capability. That is, generators' and consumers' collective access to the networks must be consistent with the networks' capacity and not cause quality, reliability or security issues.

Ensuring that access is consistent with the physical capacity of the transmission network is managed through the wholesale market's scheduling process. In any 5-minute scheduling period, AEMO's National Energy Market Dispatch Engine (NEMDE) dispatches the lowest cost combination of scheduled generators to meet forecast net demand, subject to constraints, including constraints on the transmission network. This approach is known as open access.

Generators only pay a shallow connection charge and do not pay for the use of the network. In turn, they do not receive firm access: they can be constrained off through the scheduling process. If it is necessary in order to maintain the integrity of the network, despite bidding to sell electricity at a price below the market price.

There is no obligation on transmission NSPs to provide capacity to any individual generator. However, given the obligation on transmission NSPs to reliably supply their customers, customers fund investments in the transmission network that enable export of energy from

143 AEMC, *Frequency Control Frameworks Review*, Draft report, 20 March 2018.

generators and relieve congestion where necessary to meet load reliability standards. The costs of the assets necessary to provide a reliable supply are recovered solely from load.

As with transmission NSPs, there is no obligation on distribution NSPs to provide capacity to any individual generator including retail customers with DER. Despite being an open access regime at the distribution level, distribution NSPs do not currently have the capabilities to forecast network constraints and curtail passive DER (with an export size of less than 5MW) or to provide wide scale constraint level information to another party for the purposes of optimising and dispatching active DER.

Options for access arrangements at the distribution level

An alternative to the current open access framework at the distribution level would be some form of firm access regime in which DER exporters paid for a specified level of access. However, introducing any form of firm access for DER at the distribution level would be extremely difficult to implement in practice, would likely involve considerable expenditure to remove network constraints, and would be inconsistent with the open access framework at the transmission level.

The Commission is of the view that retaining an open access framework at the distribution level maintains consistency with the open access framework at the transmission level. As discussed above, as distribution NSPs develop the capability to provide constraint information, active DER will be able to be dispatched through market systems. The Commission considers that in this context consistency between transmission and distribution levels will maintain competitive neutrality in generation. That is, generation at the transmission level and distribution level, and small-scale non-registered DER (eg household solar PV) and large-scale registered DER (eg wind or solar farms with a capacity of greater than 5MW), will be able to compete for access to markets on a level playing field meaning the lowest cost generation can be dispatched.

With respect to passive DER, it is likely that distributed NSPs will utilise connection arrangements to address risks to the power system as discussed above in section 5.2.2, and/or that there may be an increased role for some of the access standards in the NER to be extended to non-registered DER. It is important that distribution NSPs have the discretion in the connection process to address network constraints. The Commission does not consider that distribution NSPs that seek to manage passive DER through short-term curtailment to maintain distribution equipment safely within voltage and thermal limits or to protect power system security is contrary to providing open and non-discriminatory access.

Notwithstanding the above points, the Commission continues to monitor the environment for developments that may require changes to the NEM's open access framework. In particular, the Commission undertakes biennial reporting on a set of drivers that could impact on future transmission and generation investment, through its *Coordination of generation and transmission investment* review that has a focus on evaluating the transmission frameworks (including the open access regime) in respect of providing better co-ordination of investment between the transmission and generation sectors. Recently, the Commission has sought stakeholder views in the Stage 2 discussion paper for this review on the appropriateness of the existing open access regime, and whether or not this may need to change, for example, in the context of building Renewable Energy Zones.[144]

5.4.2 Interactions with connection charges and network pricing

Currently, retail customers that connect micro-embedded generation, such as solar PV, are charged a shallow, one off connection charge (i.e. they are only charged for works related to the connection between their property and the distribution network) under a basic connection service. Consistent with generators connected to the transmission network, embedded generators and retail customers with micro-embedded generators do not pay any charges related to exporting electricity onto the grid.

The existing connection charging framework provides that under certain circumstances, customers may be required to contribute towards costs associated with a standard control service. This contribution is referred to as a "capital contribution". However, there are limitations on capital contribution charges for retail customers that connect embedded generators.[145]

The connection charge principles set out in Chapter 5A of the NER prohibits retail customers (other than a non-registered embedded generator or a real estate developer) from being required to make a capital contribution towards the cost of augmenting the shared network if the application is for a basic connection service or under a relevant threshold set in the DNSP's connection policy.[146]

With respect to being charged for use of the shared network, clause 6.1.4 of the NER prohibits a distribution NSP from charging a distribution network user (such as an owner of a distributed energy resource) distribution use of system charges for the export of electricity by that user to the distribution network.

With respect to connection charging, the Commission's view is the connection arrangements for DER currently remain appropriate. The Commission considers that the costs and benefits of DER to the network and wider system, and the ability to implement more active DER management strategies, should be better understood before any potential changes to existing arrangements are considered.[147]

Should managing DER through the periodic, but rare, curtailment of passive DER, as proposed by AEMO and the ENA (i.e. dynamic export constraints), be found to provide the most value to customers, deep augmentation costs caused by the high penetration of DER will be avoided except where such an augmentation passed a regulatory investment test (RIT), in which case it would be appropriate for these costs to be passed on to customers through network charges.

Also, as DER becomes dispatchable, connection charges may not be the appropriate mechanism to incentivise or compensate DER for the provision of network and system

144 AEMC, *Coordination of generation and transmission investment*, Stage 2 Discussion paper, 13 April 2018, p. 64.

145 Clause 5A.E.1(c) of the NER.

146 Clauses 5A.E.1(b) of the NER.

147 As discussed above, further work needs to be undertaken by DNSPs, AEMO and the AER to establish these costs and benefits.

services. As the capabilities of DER increase and distribution level markets evolve, DER may increasingly be able to respond to locational and temporal price signals which will incentivise the efficient location and operation of DER.

5.5 First steps by DNSPs towards more efficient integration of DER

While much work is being done by distribution NSPs, AEMO and others, technology and markets have significant progress to make and implementing a framework for the managing and optimising DER dispatch will require further development and consultation. Implementation would also require considerable time.

Valuable work on this issue has already been undertaken by a range of bodies, including the ENA and CSIRO's Electricity Network Transformation Roadmap. The Roadmap's final report in April 2017 set out a series of recommendations to support the transformation of networks for a decentralised energy future, including recommendations that networks "develop essential information tools for a cost effective integrated grid" and the establishment of "active distribution system operations and markets".[148] The latest ENA and AEMO *Open Energy Networks* report builds on those initial recommendations.

Further work on assessing the costs and benefits of distribution NSPs developing capabilities to dynamically manage passive DER to customers will need to be done. Building these capabilities will require material investment by distribution NSPs.

However, the Commission considers that there may be a number of first steps that DNSPs can take irrespective of the specific approach and framework which is ultimately implemented.

The key first steps involves distribution NSPs building a better understanding of how much DER can be connected to their networks while meeting their regulatory obligations in respect to performance of the network and quality of supply.

This is likely to involve deploying current network modelling and monitoring capabilities into low voltage (LV) networks to understand the hosting capacity of their networks based on quantifiable factors including thermal, voltage control, power quality and relay protection limits. Development of this capability will enable:[149]

- More accurate indications to be provided to prospective DER providers and customers as to where they can most readily connect to the network and more efficient connection processes
- DNSPs to incentivise DER to locate where they provide most benefits to the network
- Development, targeting and execution of the most economic short-term strategies to increase hosting capacity, for example, the re-balancing of loads or 'tapping-down' of distribution transformers.

These capabilities will also provide the foundation for near-real time constraint assessment, enabling the more sophisticated management and orchestration of DER to progressively

148 ENA and CSIRO, *Electricity Network Transformation Roadmap*, Final Report, April 2017.

149 AEMO & ENA, *Open Energy Networks*, 15 June 2018, p. 35.

release more value from DER if this is found to be necessary. This future grid will also enable customers to be rewarded for the DER services they provide to the grid and other markets and conversely pay for the services they use.

Developing the capabilities to better understand NSPs' systems and more actively manage DER may take distribution NSPs some years, making it critical that distribution NSPs understand and start acting on these changes now. It will be important to assess the costs and benefits of possible approaches to ensure these costs are justified. The next chapter provides the Commission's views on how that can occur under the current regulatory framework.

6 THE FIRST STEPS TOWARDS TRANSFORMATION: HOW THE CURRENT FRAMEWORK CAN FACILITATE THE EFFICIENT INTEGRATION OF DER

Summary

Previous chapters outlined the customer driven transformation towards distributed energy resources and the opportunities and challenges this poses for networks. Distributed network service providers (NSPs) consider that the following actions will be necessary to meet their reliability and quality obligations in the future:

1. place potentially low, static caps on distributed energy resources (DER) exports, for example prohibiting new customers that are seeking to connect DER from being allowed to export energy once a certain threshold of DER connections in an area is reached
2. augment networks as DER exports increase and reliability and quality issues arise, or
3. implement more advanced monitoring, planning and operational strategies which enables more dynamic management of DER exports, which would minimise the need to constrain DER exports.

The costs and benefits of each of these options is being explored by distribution NSPs, Energy Networks Australia (ENA) and the Australian Energy Market Operator (AEMO). Based on the preliminary analysis done to date, the option of building the capabilities to dynamically manage DER has the potential to be the most efficient strategy to unlock the value of increased DER while minimising future network costs.

Distribution NSPs do not currently have the technology or capabilities to manage DER dynamically. Distribution NSPs currently have limited visibility of the performance of their low voltage networks or predictive capabilities of how their networks and DER will behave in real time. Nor do distribution NSPs have the capabilities to communicate and control DER if network constraints arise which threaten to compromise reliability and quality of supply or system security. Building these capabilities will require an investment by distribution NSPs.

As set out in Chapter 5, while the future model for optimising DER is still unclear and is subject to further development and consultation, the Commission agrees that building a better understanding of their networks is likely to be first steps for distribution NSPs.

The Commission acknowledges that there is currently some uncertainty as to how the National Electricity Rules (NER) would be applied to such investments because they are largely untested for this particular type of investment, but the Commission considers that the current rules are sufficiently flexible to allow distribution NSPs to recover efficient expenditure of this nature, if it can be demonstrated the expenditure will meet the capital and operating expenditure objectives.

This chapter provides the Commission's analysis on this flexibility and focuses on two aspects

of the regulatory framework: revenue regulation and planning.

6.1 Regulating network service providers – interaction between frameworks

It is important to note that the framework that regulates network service providers is complex with interaction between a number of related frameworks such as revenue regulation and planning. The regulatory instruments within these frameworks that impact on network service providers' investment decisions are set out in different parts of the National Electricity Rules (NER).

For example, provisions in relation to network connection, planning and expansions are set out in Chapters 5 and 5A while economic regulation of distribution and transmission network service providers are in Chapter 6 and 6A respectively.

The context of this framework is set out in Figure 6.1. This figure identifies the various regulatory instruments that are relevant to network investment information and decision making in addition to their key objectives.

Figure 6.1: Network investment regulatory instrument

Instrument	Frequency	Objective
Annual planning report	▪ Annual with forward planning period of five years (distribution) and ten years (transmission)	▪ Report on **expected future operation of networks** over an appropriate planning period ▪ DNSPs to develop a **demand side engagement strategy**
Regulatory investment test	▪ As required	▪ Identify an **efficient option for new infrastructure**
Regulatory information instruments	▪ As required	▪ AER sets out objectives - either a **regulatory information order** or **regulatory information notice**
Revenue proposal	▪ For each regulatory control period: normally five years	▪ Allow AER to make a **revenue determination** that sets **maximum allowable revenue** for a network service provider over a regulatory control period

6.2 Flexibility and discretion provided by the current economic regulatory framework

All distribution NSPs in the National Electricity Market (NEM) are subject to its incentive based economic regulatory framework. The Australian Energy Regulator (AER) locks in the total revenue requirement for each distribution NSP at the start of each regulatory period. It is based on the AER's estimate of the efficient costs that a distribution NSP would incur to meet its reliability standards and other regulatory obligations.

Importantly, under this approach, the AER does not approve funding for distribution NSPs' specific projects or programs. Rather, once total revenue is set, it is up to the distribution NSP to decide which suite of projects and programs are required to deliver services to consumers while meeting its regulatory obligations.

The framework provides distribution NSPs with discretion to provide services by using any combination of:

- network or non-network options
- operating or capital expenditure based approaches
- a wide variety of technologies
- procuring inputs from third parties or investing in assets directly.

As noted above, the revenue allowance set by the AER is not based on actual costs, but is based on the estimated efficient costs involved in the provision of network services for each relevant distribution NSP. If a distribution NSP spends less than the estimated efficient costs, it will retain the difference for the remainder of the regulatory control period and then share the corresponding savings with consumers in the subsequent regulatory control periods (with the incentive scheme determining what proportion of those savings is retained by the NSP and what proportion is shared with consumers).

The following sections set out in more detail the:

- revenue regulation approach and process by which the AER sets a distribution NSP's revenue requirement at the beginning of a regulatory period
- mechanisms for reviews of expenditure by the AER at the conclusion of a regulatory period.

6.2.1 Approach and process for calculating a distribution NSP's revenue requirement

The current economic regulation of DNSPs in the NEM is based on an approach where a distribution NSP's revenue requirement for a regulatory period is determined at the start of the period by the AER (often referred to as an "ex-ante" approach). The revenue assessment process commences with a distribution NSP submitting a regulatory proposal to the AER which includes the distribution NSP's forecast estimate of efficient operating and capital expenditure for the next regulatory control period. The AER assesses that proposal and considers submissions from stakeholders and prepares a revenue determination that sets out, amongst other things, the AER's decision on the distribution NSP's revenue requirement for the regulatory period.

This section provides a brief description of the expenditure forecast assessment process under the NER and the AER's current approach.

Expenditure forecast assessment provisions in the NER

The AER assesses a distribution NSP's revenue proposal to determine whether the total operating and capital expenditure forecasts provided by it reasonably reflect efficient costs.

The NER set out specific requirements against which the AER must assess and determine expenditure proposals from distribution NSPs. The AER must follow the approach it proposes to use to assess operating expenditure and capital expenditure In accordance with the *Expenditure Forecast Assessment Guidelines*.[150]

When it makes a determination, the AER decides whether or not it is satisfied that a distribution NSP's proposed total capital expenditure (capex) forecast and total operational expenditure (opex) forecast reasonably reflect the capex criteria and opex criteria (collectively, the expenditure criteria). If the AER does not consider a distribution NSP's revenue proposal is reasonable, it replaces it with its own forecast of efficient costs. Whether the AER accepts a distribution NSP's forecast or does not accept it, it is required to provide the reasons for the decision.[151]

These expenditure criteria include:[152]

- the efficient costs of achieving the capital and operational expenditure objectives
- the costs that a prudent operator would require to achieve the capital and operational expenditure objectives
- a realistic expectation of the demand forecast and cost inputs required to achieve capital and operational expenditure objectives.

The capital and operating expenditure objectives include:

- meeting or managing expected demand
- complying with all applicable regulatory obligations or requirements in relation to quality, reliability or security
- maintaining the safety of the distribution system.[153]

While there are a number of factors the AER must have regard to when deciding whether or not it is satisfied that forecast expenditure is efficient,[154] the NER allows the AER discretion in determining the methodology it will use. The NER specifies that the AER must make and publish *Expenditure Forecast Assessment Guidelines*[155] that specify the approach the AER proposes to use to assess the forecasts of expenditure that form part of distribution NSPs' regulatory proposals.[156]

The AER's approach to assessing expenditure forecasts

The AER takes the same general approach to assess a distribution NSP's forecasts for capex and opex forecasts.

150 Clause 6.4.5 of the NER.

151 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 17-21.

152 Clauses 6.5.6(c) and 6.5.7(c) of the NER.

153 Clauses 6.5.6(a) and 6.5.7(a) of the NER.

154 Clauses 6.5.6(e) and 6.5.7(e) of the NER.

155 *AER, Expenditure forecast assessment guidelines, https://www.aer.gov.au/system/files/AER%20Better%20Regulation%20factsheet%20-%20expenditure%20forecast%20assessment%20guideline%20-%20November%202013.pdf*

156 Clause 6.4.5 of the NER.

The AER typically compares the distribution NSP's total forecast with an alternative estimate which it considers reflects efficient expenditure. To calculate this alternative estimate the AER uses a range of assessment techniques such as category level analysis and trend analysis which both use historical information.[157] These assessment techniques are set out in the AER's *Expenditure Forecast Assessment Guideline for Electricity Distribution* and are summarised in Box 6.1.[158]

For recurrent expenditure, the AER typically relies on a revealed cost base-step-trend approach in its assessment. This involves using revealed (I.e. past actual) costs as the starting point for assessing and determining efficient forecasts, as the AER considers that if a distribution NSP operated under an effective incentive framework, actual past expenditure should be a good indicator of the efficient expenditure the distribution NSP requires in the future. Using revealed costs as a predictor of future costs should not be confused with a cost of service approach which sees actual costs passed through to consumers.

The AER tends to rely on revealed costs for opex to a greater extent on the basis that it considers opex as recurrent. In contrast, the AER considers that capex is largely non-recurrent or 'lumpy'.[159]

The AER also includes step changes for matters such as changes in regulatory requirements that are not included in the revealed base cost,[160] and adjustments for changes such as demand forecasts and input costs.[161]

BOX 1: ASSESSMENT TECHNIQUE USED BY THE AER

The range of assessment techniques used by the AER include to assess efficient expenditure include:

Clause S6.2.2A of the NER.

- economic benchmarking: productivity measures used to assess a business's efficiency overall
- category level analysis: comparing how well a business delivers services for a range of individual activities and functions, including over time and with its peers
- predictive modelling: statistical analysis to predict future spending needs, generally used to assess the need for upgrades
- trend analysis: forecasting future expenditure based on historical information
- cost benefit analysis: assessing whether the business has chosen spending options that reflect the best value for money

157 Ibid p.10.
158 Ibid, pp. 17-21.
159 Ibid.
160 Ibid, p.11.
161 Clause 6.12.2 of the NER.

- project review: a detailed engineering examination of specific proposed projects or programs.

6.2.2 Post revenue determination

Once a total revenue allowance has been set for a regulatory period, it is up to a distribution NSP to decide which suite of projects and programs are required to deliver services to consumers while meeting its regulatory obligations.

In general, a distribution NSP's capex in a regulatory period, once incurred, will be included in the regulatory asset base (RAB). However, in limited circumstances the AER has the discretion to determine that some capex that it considers to have been inefficient will not be rolled into the RAB.[163] One instance where the AER may make such a determination is when the distribution NSP's actual capex during the regulatory period exceeds the allowance the AER set in its determination at the start of that regulatory period, and the AER determines that the expenditure is not efficient, I.e. that it does not reasonably reflect the capex criteria. In these circumstances, the maximum amount that the AER can decide not to include in the RAB is the amount by which actual capex exceeds the capex allowance set out in the determination. If the distribution NSP's actual capex was less than its allowance, then the AER has no power to not roll that expenditure into the RAB on the basis that it was inefficient.

In undertaking this review, for both transmission NSPs and distribution NSPs, the AER must have regard to the capital expenditure factors, and can 'only take into account information and analysis that the NSP could reasonably be expected to have considered or undertaken at the time that it undertook the relevant capital expenditure'.[164] The AER uses the same techniques to conduct an ex-post assessment as it does to assess forecast capex and must demonstrate that the expenditure was not efficient. The AER will also have regard to the Regulatory investment test for distribution (RIT-Ds) in making this assessment.

If a distribution NSP overspends on its capex allowance (I.e. spends more than the efficient amount determined by the AER in the determination), it may incur a penalty under the capital efficiency sharing scheme (CESS). Equally, if a distribution NSP spends less than its capex allowance, it will earn a reward. That penalty or reward is implemented through revenue allowances in future years.[165]

If a distribution NSP overspends on its opex allowance, it may incur a penalty under the efficiency benefit sharing scheme (EBSS).[166] However, as set out above, a distribution NSP's actual opex from one regulatory control period will form the historical starting point for

163 This includes net of approved throughs less negative pass throughs.
164 Clauses S6.2.2A(h)(2) and S6A.2.2A(h)(2) of the NER.
165 Clause 6.5.8A(c) of the NER.
166 Clause 6.5.8 of the NER.

determining the opex allowance for the next regulatory control period if the AER considers it efficient. Therefore opex from this period may be built into opex allowances going forward.

6.2.3 Commission's analysis

The current framework can be effectively applied to network investments on network modelling and monitoring

As discussed above, the economic regulatory framework provides significant discretion and flexibility to the AER in how it assesses revenue proposals for efficiency and prudency. The framework also provides distribution NSPs significant flexibility in how they spend capital and operational expenditure within the overall revenue requirement determined by the AER.

The Commission considers that this framework can be effectively applied to network investments related to modelling and monitoring of distribution NSPs' low voltage (LV) networks. The Commission understands that some distribution NSPs have expressed uncertainty as to how this type of expenditure would be assessed by the AER, and a reluctance to incur this type of expenditure without an assurance from the AER that it will be considered efficient and included in their revenue requirements.

However, it is also important that NSPs recognise their key role in the transforming energy system. NSPs are best placed to make the technical and commercial decisions for their businesses and the current incentive regulation framework contains a number of mechanisms that should provide distribution NSPs with confidence that they can recover efficient costs.[167] Under an incentive regulation, there is never a guarantee that the actual costs of any individual project can be recovered by distribution NSPs.

The current framework provides distribution NSPs and the AER with discretion and flexibility

As explained above the existing economic regulatory framework provides distribution NSPs with significant discretion and flexibility during a regulatory period. The AER does not approve individual projects and instead only approves an overall revenue requirement. Accordingly, it is not a matter of the distribution NSP needing to demonstrate to the AER that a specific proposed investment is efficient and can be undertaken.

Once a distribution NSP's total revenue has been set, the framework provides distribution NSPs with the flexibility to:

- make a combination of capital and operating expenditure, for example on the deployment of monitoring equipment or procurement of data from a third party such as a Metering Coordinator,
- prioritise which investment is most important, for example by investing in projects such as building advanced monitoring capabilities ahead of other projects.

167 Unlike a cost-of-service regime in which projects are assessed on a case by case basis by the regulator and these costs are passed through to consumers, projects do not require regulatory approval under an incentive based regime nor is a network guaranteed the cost of service.

The Commission acknowledges that a distribution NSP would only be able to 'swap out' projects (I.e. undertake investment in improved network modelling and monitoring instead of other projects) and stay within its total revenue requirement if this did not compromise its regulatory obligations in respect to reliability and quality. However, based on preliminary information provided by distribution NSPs, the Commission understands that the amount of expenditure that is likely to be required to improve network modelling and monitoring is expected to be relatively small as a proportion of distribution NSPs' total revenue requirements. In addition, the current framework relies to a significant extent on a revealed costs approach. This means that if a distribution NSP undertakes expenditure of this nature and it becomes part of its "business as usual" expenditure, then that expenditure is likely to be used by the AER to inform future revenue allowances (being either capital or operating expenditure) unless the AER determines that the expenditure was inefficient.

Applying the framework: practical considerations

While the costs of implementing advanced monitoring, planning and operational strategies an be estimated reasonably effectively, it could potentially be more difficult for the distribution NSPs who are first to propose these strategies to demonstrate the expected benefits. Similarly, the AER will face new challenges in assessing proposals for expenditure on technologies and approaches which have not been widely implemented in the NEM or internationally.

The AER has refined its methodologies for assessing expenditure proposals including its base-step-trend model, benchmarking and its replacement expenditure (repex) model. The AER may need to further adapt its existing methodologies to forecast efficient expenditures in order to take into account the changing energy environment and assess the next regulatory proposals from networks which have increasing uptake of DER. The rules provide the AER considerable flexibility as to how to apply these methodologies.

Involving consumers will also be an important input to forecasting efficient expenditure levels for this type of investment. The AER recognises this, pointing out in recent Framework and Approach papers that consumer engagement is becoming increasingly important in the development of proposals by NSPs.[168] The ENA, AER and Energy Consumers Australia (ECA) are also jointly trialling a different consumer engagement approach through the NewReg initiative.[169] The trial aims to improve engagement on regulatory proposals and reach agreement between the distribution NSP and a forum of consumer representatives before the proposal is submitted to the AER. Such an approach has the potential to significantly reduce uncertainty for the distribution NSP if consumers agree that proposed investments are likely to deliver benefits to consumers.

As discussed in the next section, the regulatory investment test for distribution RIT-D may also apply to this type of expenditure. The AER is required to have regard to the outcomes of a RIT-D when assessing capex, and distribution NSPs can have a reasonable degree of

168 AER, *Preliminary framework and approach - SA Power Networks- March 2018*, p.13.

169 For more information see: https://www.aer.gov.au/networks-pipelines/better-regulation.

confidence that expenditure that has passed a RIT-D assessment will be included in the capex allowance and rolled into the RAB.

The NER also allow the AER to approve a "contingent project" as part of a determination. This mechanism is often used for projects where it is not clear at the start of the regulatory period whether the project will be required, for example projects that will only be needed if demand reaches a certain level. Contingent projects are approved subject to certain triggers being met, one of which is often completion of a RIT. There may be scope of to use the contingent project mechanism for some LV modelling and monitoring investments so that the distribution NSP can start recovering expenditure related to the project part way through a regulatory period if it passes a RIT-D.

6.3 Interactions with the planning framework – valuing DER

The Commission considers that there would be benefit in the AER providing further guidance in its current review of the application guidelines for the regulatory investment tests for transmission and distribution on how these types of identified needs should be assessed under the RIT-D.

The NER contain specific requirements for distribution NSPs to undertake, subject to some exemptions, a RIT-D process to determine the most appropriate solution to an "identified need". An example of such an "identified need" would be the need to invest in the network to maintain the voltages within the levels under Schedule 5.1 of the NER. This obligation sits alongside the AER's assessment of efficient capital expenditure for the regulatory control period as an additional measure to increase assurance that consumers are only charged for efficient network expenditure.

The RIT-D applies to projects that address an identified need for which the expenditure exceeds $5 million (which includes replacement expenditure).[170]

The AER states in the *Regulatory investment test for distribution application guidelines* that an identified need may consist of:[171]

- meeting any of the service standards linked to the technical requirements of Schedule 5.1 of the NER, or in applicable regulatory instruments (referred to as "reliability corrective action") and/or
- an increase in the sum of consumer and producer surplus in the NEM (which is assessed by reference to various types of "market benefits").

The purpose of the RIT-D is to identify the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM (the preferred option). However, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the "identified need" is for reliability corrective action.[172]

170 Clause 5.13(b) of the NER; the figure of $5 million is current as at June 2018, with this figure subject to annual review by the AER.

171 AER, Regulatory investment test for distribution application guidelines, 18 September 2017, p.7.

172 Clause 5.17.1(b) of the NER.

The NER requires the AER to develop and publish guidelines for the operation and application of the RIT-D, including providing worked examples.[173] The AER is currently undertaking a review of the application guidelines for the regulatory investment tests and published an issues paper in February 2018.[174]

An investment program of greater than $5 million to meet an identified need by deploying increased monitoring into low voltage networks by distribution NSPs would likely be required to undergo a RIT-D. If investments were needed to augment or replace the capacity of networks to accommodate increased levels of DER while complying with applicable regulatory obligations these would also be required to undergo a RIT-D.

Depending on what exactly the identified need is, and what type of investment is proposed, how the RIT-D would be applied in practice may vary. If the increased uptake of DER was creating reliability issues (e.g. impacting a distribution NSP's ability to comply with its obligations as set out in Schedule 5.1 of the NER or in relation to jurisdictional requirements) then this would be the "identified need" and the distribution NSP could undertake a RIT-D to assess various investment options to identify the option it should take to resolve this issue.

As indicated in the case study in Chapter 4, we understand that some distribution NSPs are already undertaking network expenditure to manage technical issues such as shifting voltage levels caused by high penetration of DER. Although those individual investments have to date been under the RIT-D threshold, it is likely in the future that some of those investments will exceed the $5 million threshold, noting that the RIT-D provisions in the NER allow for "a single assessment of an integrated set of related and similar investments".[175]

Traditionally, most major "reliability corrective action" projects undertaken by distribution NSPs would relate to meeting jurisdictional reliability obligations related to load, for example expanding the network to meet peak demand. However, as noted above the AER's RIT-D application guidelines currently state that reliability corrective action includes identified needs that consist of "meeting any of the service standards linked to the technical requirements of schedule 5.1 of the NER, or in applicable regulatory instruments". This part of the RIT-D would therefore appear to extend to actions needed to meet distribution NSPs' other obligations under Schedule 5.1 and jurisdictional obligations, including operating within prescribed voltage limits.

Under the NER, networks can also consider "market benefits" under the RIT-D process.[176] The NER contains a prescriptive list of classes of market benefits that RIT-D proponents are required to consider.[177] Those market benefits include matters such as changes in voluntary load curtailment, involuntary load shedding and customer interruptions caused by network outages and changes in generation costs. A distribution NSP may also consider any other

173 Clause 5.17.2(a) of the NER.

174 For more information on the AER's review of the application guidelines for the regulatory investment tests for transmission and distribution see: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-the-application-guidelines-for-the-regulatory-investment-tests-for-transmission-and-distribution

175 Cause 5.17(e) of the NER.

176 Networks can also consider the costs incurred and benefits derived in other parts of the NEM under in the Demand Management Incentive Scheme.

177 Clause 5.17.1(c)(4) of the NER.

class of market benefit determined by the AER to be relevant. As noted above, the AER must also provide guidance and worked examples to the acceptable methodologies for valuing the market benefits of a credible option as part of the RIT-D application guidelines.[178]

The Commission consider that there are a range of market benefits that would potentially arise from investment in improved modelling and monitoring by DNSPs of their LV networks. For example:

- LV constraints caused by high penetration of DER are only likely to bind rarely. If distribution NSPs do not have a good understanding of those constraints and there is no ability to actively manage DER when constraints bind, distribution NSPs are likely to manage those potential constraints more conservatively by augmenting networks to reduce this risk. Improved forecasting of constraints and the tools to manage them could enable distribution NSPs to meet expected standards at the lowest possible cost. Improved understanding of constraints and improved tools to manage them should allow higher levels of DER to be dispatched without constraints, which could also reduce overall generation costs by enabling greater use of zero marginal cost solar photovoltaic (PV) that would otherwise be constrained or denied a connection.
- If distribution NSPs are able to forecast and manage network constraints, DER may also be able to increasingly play a role in frequency control ancillary services (FCAS) markets, voltage control, and other valuable services, improving system security and reducing load shedding and network outages.

To date, there have not been any RIT-Ds that have considered this type of investment so there are limited precedents for distribution NSPs to understand how they would be assessed under the RIT-D, although some parallels can be drawn with RIT-Ts undertaken by transmission NSPs in relation to investments by transmission NSPs to reduce transmission constraints.

As part of its current review of the applications guidelines for the RITs, the AER has the opportunity to consider whether additional classes of market benefits may be appropriate or more guidance on how to apply current classes of market benefits.[179]

As part of a RIT-D process, the distribution NSP will also need to consider the methodology for valuing the market benefits of DER. We consider that there would be benefit in the AER providing increased guidance on the methodologies for valuing market benefits and including worked examples for distribution NSPs as part of its review of the application guidelines. Worked examples demonstrating a market benefit would be useful in relation to both to building monitoring capabilities if the AER considers this to be a RIT project and an augmentation of the distribution network to increase the hosting capacity for DER.

The Commission considers that establishing methodologies for valuing DER across a range of situations in which DER provides value to the network and wider market would have a number of benefits and would enable:

178 Clause 5.17.2(c)(5) of the NER.

179 See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-the-application-guidelines-for-the-regulatory-investment-tests-for-transmission-and-distribution

- distribution NSPs to transparently reflect the network value in their planning and investment decision making
- DER proponents to develop credible proposals to offer to DNSPs in place of network solutions.

7 AREAS OF FOCUS FOR FUTURE REVIEWS

The consumer driven transformation of the electricity sector has been well-documented and this transformation is likely to continue and accelerate over coming years. Preceding chapters of this report discussed the need for two areas of reform to facilitate the efficient integration of distributed energy resources (DER) in the electricity system. As the role of network service providers (NSPs) continues evolve in response to the electricity system's continual transformation, other reforms may be needed so that the economic regulatory framework continues to serve the long term interest of electricity consumers. In the longer term, it is possible that more fundamental reforms to aspects of the regulatory framework will be required to allow the preferred approach to DER integration to be achieved.

As the terms of reference requests this review to be conducted annually, this chapter sets out the other issues the Commission intends to consider in next year's review.

7.1 Towards network transformation – efficient integration of DER

Chapter 4 of this report discussed how the role of NSPs is expected to evolve as the electricity market continues to transform. In addition to providing safe, secure and reliable electricity to customers, NSPs are likely to be involved, in one form or another, in facilitating the efficient integration of DER into the electricity system.

The Commission will continue to progress the discussion already underway on the future roles of NSPs by building on the work commenced by the *Distribution Market Model* project and progressed in this year's report, as well as other initiatives conducted by other stakeholders. In particular, the Commission will work closely with Australian Energy Market Operator (AEMO) and Energy Networks Australia (ENA) through their consultation on the framework for distribution level optimisation and identify any regulatory changes that are required to support the efficient integration of DER.

The Commission is also working with AEMO to develop a joint work program on DER with the objective of better coordinating the various areas of work that the Commission and AEMO are currently undertaking on a range of DER-related issues. The Commission will also work closely with the AER on this work, and the other areas of potential reform discussed in this report.

7.2 Promoting efficient network investment

Chapter 7 discusses the Commission's concerns that the current method of separate assessment and remuneration of capital expenditure (capex) and operating expenditure (opex) is not likely to support the continual transformation of the electricity sector and that a holistic review of the method of expenditure assessment and remuneration is required.

Expenditure assessment and remuneration, while an important aspect, is not the only part of the framework. Changes to this part alone may not be sufficient to promote efficient network investment in a transforming system; nor is it likely that a different approach such as a total expenditure framework (totex) alone would resolve every issue and challenge faced by the electricity sector as it continues to transform.

Overseas jurisdictions that have considered and implemented changes to their expenditure assessment and remuneration framework have generally also considered complementary changes. For example, Ofgem's RIIO framework included output targets and enhanced innovation components alongside the totex method of expenditure assessment. Ofwat also took a similar approach and adopted totex within an outcomes and customer engagement framework. Other overseas regulators such as Italy's AEEGSI and the New York Public Service Commission recognised that focusing on the method of expenditure assessment and remuneration would not be sufficient in addressing the challenges faced by network service providers in a changing environment.[180]

The sections below provide a brief description of the issues that the Commission will consult on in addition to expenditure assessment and remuneration to understand whether there is already sufficient flexibility in the current regulatory regime or whether reforms are required.

7.2.1 Output/performance based regulation

As discussed above, a number of overseas regulators have included output or performance based target as part of a suite of tools to promote efficient investment and achievement of certain outcomes. For example, Ofgem's RIIO framework contains a number of output based targets in addition to traditional incentive schemes. The output based targets cover areas such as safety, customer satisfaction and social obligations. Similarly, Ofwat's PR14 methodology also introduced outcome incentives to cover areas such as quality, reliability and environmental protection.[181]

In the National Electricity Market (NEM), the service target performance incentive scheme (STPIS) has been a long standing feature under the National Electricity Rules (NER), but the current STPIS is focused on supply reliability and does not cover other areas. The Australian Energy Regulator (AER) also has the power under the NER to develop small scale other incentive schemes, but has not done so to date. Jurisdictional governments and jurisdictional regulators also set output requirements through a range of jurisdictional obligations related to reliability, quality and safety.

A move towards increased use of performance based regulation could involve an enhancement and evolution of the current use of incentive mechanisms, or a more fundamental shift to a regime where regulated revenues are based more on performance outcomes and less on estimates of efficient costs.

As part of next year's review, we will consult on whether the NER contain sufficient flexibility to move to a more output or performance based form of regulation if warranted, or whether regulatory changes are needed.

180 KPMG, *Optimising network incentives: alternative approaches to promoting efficient network investment*, p. 110, 129.

181 Frontier Economics, *Total expenditure frameworks: a report prepared for the Australian Energy Market Commission*, p.76.

7.2.2 Consumer engagement

The recent transformation of the electricity system was largely driven by consumers. In a future where potentially a large proportion of the electricity is generated by end-use consumers, the regulatory framework needs to facilitate engagement of stakeholders across all levels.

NSPs have made significant improvements in how they have engaged with consumers in recent years in relation to development of their regulatory proposals and tariff structure statements, triggered in part by changes the Commission made to the rules in 2012 to require NSPs to explain how they have engaged with consumers in developing their proposals. The AER has also adopted a range of new consumer engagement techniques such as its consumer challenge panels.

In recognition of the need to adopt an even more consumer orientated approach to network regulation, ENA, the AER and Energy Consumers Australia (ECA) established the *NewReg*[182] project aimed to improving engagement on network revenue proposals and identify opportunities for regulatory innovation. The project is testing an alternative approach to network revenue proposal via a trial with AusNet Services 2021-25 regulatory control period where AusNet Services will seek to reach agreement on its proposal with a consumer forum before submitting it to the AER.

As part of the *2019 Economic regulatory framework* review, the Commission will work closely with ENA, ECA and the AER to monitor and consider learnings and outcomes of the trial and any recommended changes to the NER.

7.2.3 Allocation of risk between NSPs and consumers

Risk allocation under the current framework

As discussed in Section 1.5, the current regulatory framework does not provide NSPs with a 'guaranteed' rate of return or a right to recover their actual costs. Under the current regulatory framework, certain risks are borne by the NSPs while others are shared with consumers. Table 7.1 below provides a description of some of these risks under the revenue cap form of regulation that is currently applied by the AER for most NSPs.

Table 7.1: Risk allocation between NSPs and consumers

LIKELY SCENARIO	IMPACT	LIKELY BEARER OF RISKS
Actual demand higher than demand forecast in regulatory determination		
• An NSP's regulatory determination provides a lower than required expenditure allowance given actual demand	• Where an NSP incurs higher expenditure than allowed by the regulatory determination, it will bear those additional costs,	• Both NSPs and consumers share the risk of differences between actual and forecast demand in proportions

182 See: https://www.energynetworks.com.au/newreg

LIKELY SCENARIO	IMPACT	LIKELY BEARER OF RISKS
levels. An NSP could meet the unexpected demand through higher capex and/or opex within the regulatory period in order to meet legislated reliability standards	subject to some sharing with consumers under the capital efficiency sharing scheme (CESS) and efficiency benefit sharing scheme (EBSS) • Impact exacerbated if network prices are not cost reflective	determined by the CESS and EBSS
Actual demand lower than demand forecast in regulatory determination		
• An NSP's regulatory determination provides a higher than required expenditure allowance given actual demand levels. Two possible outcomes could occur: • The NSP could continue to invest based on the determination, which leads to inefficient investment • The NSP could defer or cancel investment plans, which will lead to revenues exceeding actual costs for the duration of the regulatory period	• Where investment occurs anyway: • Capex would be rolled into the RAB. • Potential under-utilisation of network assets • Regulatory investment test requirements may prevent this outcome arising depending on the size and timing of the investment • If investment does not occur or is deferred: • NSP gains financial benefits for the duration of the regulatory period • Impact exacerbated if network prices are not cost reflective	• Where expenditure occurs anyway, consumers bear the cost of over-investment as incurred capex would be rolled into the RAB and recovered from consumers over time • Where expenditure does not occur or is deferred, the benefits are retained by the NSP for the regulatory period and then shared with consumers in the next regulatory period
NSP's input costs are higher or lower than expected		
• An NSP's input costs	• Mismatch between cost	• The NSP largely bears

LIKELY SCENARIO	IMPACT	LIKELY BEARER OF RISKS
Changes in regulatory obligation during a regulatory period		
• An NSP's regulatory obligations may change during a regulatory period – for example, a change in jurisdictional reliability standards (increase or decrease)	• Mismatch between cost incurred by the NSP and estimated efficient cost for the duration of the regulatory period	• Where the costs arising from the change in obligation are less than the threshold for 'pass through events', the NSP bears the risks or rewards during the regulatory period. • Where the costs arising from the change in obligation is greater than the threshold for 'pass through events', consumers bear the risks and the rewards.

Risk allocation in the context of significant change in the operating environment

As discussed in Chapter 3, the past decade saw a significant growth in NSPs RABs, but RABs have generally flattened or slightly decreased in the last 2-3 years.

Under the current framework, when deciding the RAB roll-forward for a NSP at the start of a regulatory period, the AER has the ability to review the efficiency of NSP's capex during the previous regulatory period only if the total capex over the previous regulatory period exceeded the capex allowance set by the AER in its determination for that period. Under this limited power, the AER also only has the ability to review the amount of the overspend above the allowance and it cannot reduce the amount of capex that is rolled into the RAB to an amount that is below the level of the allowance set by the AER in its determination for that period.[183]

For the *2019 Economic regulatory framework* review, the Commission will consult with stakeholders on whether extending the AER's ability to conduct ex-post capex reviews to all capex from the previous regulatory period would be an appropriate tool to manage future risks of over-investment by NSPs.

7.2.4 Regulatory sandbox

A regulatory sandbox is an arrangement to allow businesses to trial innovative products and services, business models and delivery mechanisms that cannot operate under existing regulations. These trials generally run for a fixed period of time with a limited number of

183 See clause S6.2.2A of the NER.

customers. Ofgem's 'Innovation Link' offers a regulatory sandbox if it considers the innovative proposition meets its sandbox eligibility criteria. The criteria require the proposal to be genuinely innovative, have the potential to deliver benefits to consumers and that consumers will be protected during the trial and that regulatory barriers inhibits the progress of the trial. Ofgem's sandbox guideline also states that the regulatory sandbox is not a means to permanently change regulation. To make permanent change to regulations, Ofgem would need to follow appropriate processes and make the changes available to all parties.[184]

It is likely that technological change and innovation would transform the electricity sector faster than the changes that occurred in the past decade. Where innovation may benefit consumers, there may be merit in applying a regulatory sandbox arrangement so that any changes to the regulatory framework can be fast tracked.

Under the current regulatory framework, trials and other forms of regulatory innovation can be facilitated by the AER exercising its enforcement discretion, including its powers to issue "no action letters". The Commission's current view is that this power can be used to enable regulatory sandboxes and other forms of innovation. However, the Commission is interested in stakeholders' view on the need for any more formal regulatory sandbox for the NEM or whether current arrangements already allow for a similar arrangement to occur.

7.3 Continue implementation of existing reform - network pricing

7.3.1 Why cost reflective tariffs are important

As discussed in Section 5.2.1, NSPs have found that increased uptake of DER has not to date had a significant effect on reducing network peak load. Instead, the uptake of DER to date (mainly household solar PV) has primarily moved network peak from the afternoon to later in the day. Numerous Australian and international trials conducted have showed that network tariff reform, in combination with more active management of DER, is able to promote more efficient use of network infrastructure.

While reforms discussed in this report are important in facilitating network transformation in promoting more efficient investments in network infrastructure and providing a foundation for distribution level markets, network tariffs reform also plays an important role. Cost reflective network pricing will support the continual transformation of the network by enabling more efficient usage and investment decisions by consumers. In particular, network tariff reform will provide investment signals to DER providers and help unlock the DER value stack by assisting consumers to optimise their energy usage in ways that enable them to reduce their energy costs.

Network tariff reform will also lead to more efficient utilisation of the network in the medium to long term, reducing network costs and charges for consumers. Research undertaken for the Commission as part of its *Distribution network pricing arrangements* rule change in 2014 showed that 70-80 per cent of customers would have lower charges in the medium term under a more cost reflective network prices, with average annual network charges for

184 Ofgem, *Regulatory Sandbox Window 2 Guidance*, https://www.ofgem.gov.uk/system/files/docs/2017/10/regulatory_sandbox_window_2_guidance.pdf, accessed 4 June 2018.

residential customers forecast to reduce by up to $145 a year.[185] Research also shows that the biggest beneficiaries of these savings are expected to be consumers in a hardship program, with 79 per cent of those customers expected to pay less under a demand tariff.[186] Based on trials undertaken in Victoria, the Commission's research also found that small businesses could save over $2,000 a year, or 34 per cent of their total annual network charges, by using less electricity at peak times for just 20 hours a year when networks are congested.

The Commission considers that it is not necessary for retailers to structure their prices in a way that matches network prices. Network prices are not paid directly by customers, and are instead charged by networks to retailers. If network prices are cost reflective, this will incentivise retailers and other energy service providers to offer innovative solutions to help consumers manage their demand and costs. Retailers will also play an important role in removing complexity for consumers, just as they currently do in managing a wholesale price that varies every 30 minutes and packaging that into a retail price that is simpler for consumers to understand and respond to.

7.3.2 Progress of network tariffs reform

The requirement for NSPs to develop cost reflective network prices was introduced by the Commission's *Distribution network pricing arrangement*[187] rule change in 2014. The rule change also requires NSPs to develop a tariff structure statement (TSS) that outlines the price structures that they will apply for the next regulatory period.

In its recent Retail Electricity Pricing Inquiry, the Australian Competition and Cosnumer Commission (ACCC) made several recommendations to accelerate the take-up of cost reflective network prices. The Commission supports those recommendations. No further changes to the rules are required to implement cost reflective network prices and accelerate their take-up: the necessary changes were made in the Commission's 2014 rule change and are currently being implemented by NSPs and the AER. The Commission also notes that one of the ACCC's recommendations was that there be a requirement on retailers to provide a retail offer using a flat rate structure as part of the transition to cost-reflective network pricing. The mechanism for a jurisdictional government to implement such a requirement already exists in the National Energy Retail Law, and no further rule changes are required to do so.[188]

The first TSS period, which was an interim period from 2017-18 to 2019-20, has seen distribution NSPs gradually shift their tariff structures from consumption-based and declining block tariffs (where electricity consumption becomes cheaper as it increases) in favour of time of use (TOU) tariffs and demand tariffs. TOU tariffs have higher charges for consumption during peak usage times and lower charges for consumption during times when demand on the network is lower. Demand tariffs involve adding a demand charge to network

185 AEMC, *Distribution network pricing arrangements rule change final determination*, 27 November 2014.

186 Research by AGL referred to in the AEMC's Distribution network pricing arrangements rule change final determination, p 49.

187 *AEMC, Distribution Network Pricing Arrangements, https://www.aemc.gov.au/rule-changes/distribution-network-pricing-arrangements*

188 See sections 22(1a) and 22(1b) of the National Energy Retail Law.

charges based on either the customer's maximum demand at any time of the day or the customer's maximum demand during the network's peak charging window. Under either tariff structure, the regulatory framework prevents distribution NSPs increasing the total amount of revenue they recover from consumers, so any increase in one part of the tariff is offset by a reduction in other parts of the tariff.

Cost reflective network tariffs in the first TSS period were generally offered on an 'opt-in' basis, which has led to a slow uptake of cost reflective tariffs so far. In Victoria, distribution NSPs proposed an opt-out approach in the original proposed tariff strcuture statements statements they submitted to the AER, with a range of measures to assist customers with the transition. However, they were required by legal instruments made by the Victorian government to instead adopt an opt-in approach. Those instruments only apply for the first TSS period, and are due to be reviewed by the Victorian government before the second TSS period starts in Victoria in January 2011. During the first TSS period, a slow transition to cost-reflective network tariffs outside of Victoria had limited practical impact given the limited penetration of advanced meters. However, as remotely-read interval meters are progressively rolled out across the NEM under the Commission's *Competition in metering* rule change, any further delays in the implementation of network tariff reform will have greater adverse impacts for customers.

Table 7.2 below shows a comparison of NSPs' tariff assignment policy in the interim and upcoming TSS periods that operate for a five year period starting between 1 July 2019 (for distribution NSPs in New South Wales, the Australian Capital Territory, the Northern Territory and Tasmania) and 1 January 2011 (for distribution NSPs in Victoria). The Commission notes that for the upcoming TSS period, many NSPs have started to shift to 'opt-out' or mandatory assignment policies. The Commission notes this is a positive development and endorses the ACCC's recommendation that all distribution NSPs adopt mandatory assignment of cost-reflective network tariffs in the upcoming TSS period. The Commission encourages market participants, governments, consumer groups and the AER to continue to progress implementation of network tariff reforms through the current tariff structure statement processes for the regulatory periods commencing from July 2019.

Table 7.2: Network tariffs assignment policy - comparison between interm and upcoing TSS period

DISTRIBUTION NSP	CURRENT TSS PERIOD		UPCOMING TSS PERIOD	
	TARIFF STRUCTURE	TARIFF ASSIGNMENT APPROACH	PROPOSED TARIFF STRUCTURE	PROPOSED TARIFF ASSIGNMENT APPROACH
Ausgrid	TOU	Opt-in	TOU	Assigned to TOU unless opt-out to transitional TOU

DISTRIBUTION NSP	CURRENT TSS PERIOD		UPCOMING TSS PERIOD	
	TARIFF STRUCTURE	TARIFF ASSIGNMENT APPROACH	PROPOSED TARIFF STRUCTURE	PROPOSED TARIFF ASSIGNMENT APPROACH
Essential Energy	TOU	Opt-in	Varies depending on customer type	Solar and battery: assigned to demand unless opt-out to TOU Other customers: Opt-in to demand
Endeavour Energy	TOU	Opt-in	Demand	Opt-in
Energex/Ergon	TOU/Demand	Opt-in	Demand	Assigned to demand unless opt-out to consumption
Evoenergy (formerly ActewAGL Distribution)	TOU	Opt-out	Demand	Assigned to demand unless opt-out to TOU
Power and Water Corporation	Single rate	Mandatory	Demand	Mandatory
SA Power Network	Demand	Opt-in	TOU	Assigned to TOU, opt-in to demand
TasNetworks	Demand	Opt-in	Demand	Opt-in
Victorian distribution NSPs	Demand	Opt-in	To be determined - Victorian distribution NSPs have held workshops as part of their preparation for their upcoming regulatory proposals.	

Note: Proposed tariff assignment approach based on proposed TSS's submitted to AER or discussions with NSPs.

A CHANGES TO THE LARGE SCALE GENERATION MIX

The National Electricity Market (NEM) is facing unprecedented changes to the large scale generation mix. This section provides a monitoring update on the observed changes to the generation mix, its impacts on the system and measures being taken by the Commission to address the emerging impacts.

A.1 The changing generation mix

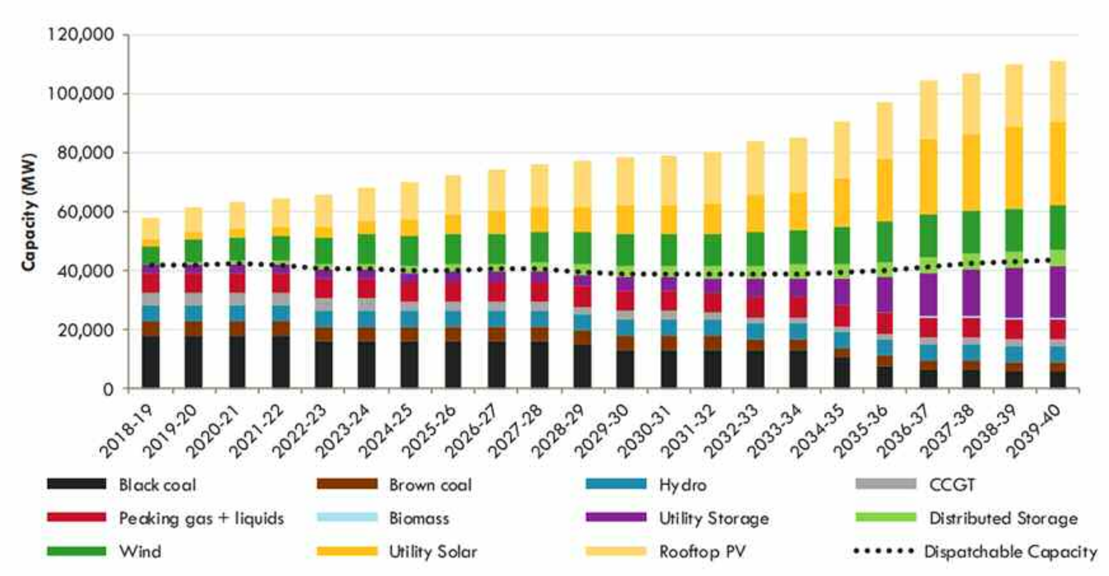
The large scale generation mix has undergone significant changes in the past with a trend towards reduction in baseload thermal generation and an increase in variable renewable generation. The Australian Energy Market Operator (AEMO) highlighted that over the last decade 5,199 MW of baseload generation had retired. The same period saw an entry of 2,898 MW of gas-powered generation (GPG), 2,965 MW of Wind, 273 MW of Hydro, 265 MW of grid-scale Solar PV, 91 MW of liquid fuel and 186 MW of other sources.[189]

The continued entry of variable renewable energy generation and an exit of thermal dispatchable generation are expected to continue to shape the future generation mix of the NEM. AEMO modelling suggests the future generation capacity in the NEM is expected to have a declining share of coal fired generation capacity and increasing share of variable renewable energy generation capacity, as shown in Figure A.1.[190] This trend can also be viewed as a replacement of generation that is synchronous and dispatchable with variable renewable energy generation.

189 AEMO, *AEMO Observations: Operational and market challenges to reliability and security in the NEM*, 2018, p.16.

190 AEMC, *Draft Report: Frequency Control Frameworks Review*, February 2018, p.21.

Figure A.1: Forecast of NEM generation capacity mix



Source: AEMO, Integrated system plan, p.37.

A.2 Impacts of the changing generation mix

The changing generation mix and increased investment in wind and solar generation has several implications for the NEM. The reducing proportion of generation that is synchronous and dispatchable, and increasing levels of renewable generation capacity expected to enter the market poses challenges for:

- **System security:**[191] the reducing share of synchronous generation can lead to reduced system strength and increases the potential for imbalances between electricity supply and demand through a reduction in frequency control capability. Frequency control challenges can arise due to reduced system inertia, potential reduction in availability of ancillary services and increased variability and unpredictability of supply and demand.
- **System reliability:**[192] variable renewable generation is non-dispatchable and intermittent. This means that it cannot ramp up when, say, a shortage is emerging or down as required, to balance the supply with demand.
- **Coordination of generation and network investment:** the new renewable generation capacity expected to enter the market is likely to be remote from the locations where ageing generation is expected to retire.

191 The ability to operate the system within defined technical limits.

192 Having enough generation, demand response and network capacity to supply consumers.

A.3 Measures to manage the impacts of the changing generation mix

To manage the impacts of the changing generation mix, the Commission is undertaking the system security and reliability work program which comprises of a number of reviews and rule changes to address the risks to power system security and reliability. The Commission's program is complemented and supported by the work undertaken by AEMO as part of its future power system security program. Some of the key projects to address system security challenges include:

- **System security market frameworks review:** the self-initiated review completed in June 2017 was aimed at identifying the required changes to market and regulatory frameworks to deliver the technical solutions for maintaining system security.[193] Three of the recommendations of the review have been addressed through rule changes including:
  - managing the rate of change of power system frequency rule change, which set out a framework to deliver the minimum inertia required to maintain system security
  - managing the power system fault levels rule change, which set out a framework to deliver the minimum fault levels required to maintain system security
  - generating system model guidelines rule change, which allows AEMO and NSPs to access accurate model data to support the provision of the required fault levels
- **Frequency control frameworks review:** the self-initiated review continues consideration of a number of recommendations made by the Commission in the *System security market frameworks review*[194], the *Distribution market model*[195] project as well as some key recommendations of the Finkel review focused on frequency control.[196]
- **Generator technical performance standard rule change request:** the rule change considers a number of changes to the technical performance standards for generators seeking to connect to the NEM, and the process for negotiating those standards.[197]

To addresses the system reliability challenges, some of the Commission's key projects include:

- **Reliability frameworks review:** the self-initiated review is aimed at providing recommendations to the Council Of Australian Governments (COAG) Energy Council on any framework changes required to maintain the NEM's existing high reliability performance, as the electricity system transforms to accommodate more variable generation and a larger presence of demand-side resources, as well as some key recommendations of the Finkel review.[198]

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193 AEMC, *System Security Market Frameworks Review*, viewed :March 2018, https://www.aemc.gov.au/markets-reviews-advice/system-security-market-frameworks-review

194 *AEMC, System security market framework review, https://www.aemc.gov.au/markets-reviews-advice/system-security-market-frameworks-review*

195 *AMEC, Distribution market model, https://www.aemc.gov.au/markets-reviews-advice/distribution-market-model*

196 AEMC, *Frequency control frameworks review, viewed*: April 2018, https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review

197 AEMC, *Generator technical performance standard*, viewed: May 2018, https://www.aemc.gov.au/rule-changes/generator-technical-performance-standards

198 AEMC, *Reliability Frameworks Review*, viewed : May 2018, https://www.aemc.gov.au/markets- reviews-advice/reliability-frameworks-review

- **Declaration of lack of reserve conditions rule change:** a rule change made in December 2017 modifying the framework for the declaration of lack of reserve (LOR) conditions to be more flexible and transparent.[199]
- **Reliability Panel's review of reliability standard and setting 2018:** the Reliability Panel's four yearly check-in recommended that the reliability standard and settings for the NEM remain unchanged for the next period.[200]

The Commission is undertaking the *Coordination of generation and transmission investment review*[201] to report on a series of drivers that could impact on the coordination of future transmission and generation investment. Stage 2 of the review is considering options for improving this coordination, including potential renewable energy zones, transmission pricing and access.

A full list of the Commission's projects related to addressing the challenges to system security and reliability can be accessed here: https://www.aemc.gov.au/our-work/our-current-major-projects/system-security-and-reliability

199 AEMC, *Declaration of Lack of Reserve conditions*, viewed: May 2018, https://www.aemc.gov.au/rule- changes/declaration-of-lack-of-reserve-conditions

200 Reliability Panel, *Reliability standard and settings review 2018*, viewed : April 2018, https://www.aemc.gov.au/markets-reviews-advice/reliability-standard-and-settings-review-2018

201 *AEMC, Coordination of generation and transmission investment, https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi*