REVIEW

Australian Energy Market Commission

2017 REPORT

Electricity Network Economic Regulatory Framework Review

18 July 2017

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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.

Executive summary

This is the first annual *Electricity networks economic regulatory framework review* report prepared by the Australian Energy Market Commission (Commission). This report is prepared under the standing terms of reference provided by the Council of Australian Governments (COAG) Energy Council.[1]

The Commission has used the first report to review the operation of the economic regulatory framework, how it has evolved against the backdrop of change in the past decades and identified areas that may require further investigation in future reports. As the first report of the annual review, the 2017 report provides a foundation for assessing the performance of the framework, rather than recommending changes.

A sector in transition

The energy sector is undergoing significant change. The national electricity market (NEM) is moving from predominantly large-scale synchronous generation to non-synchronous, intermittent generation and from centralised generation to greater amounts of smaller, distributed generation. At the same time, households and businesses are changing the way they use electricity and how they engage with participants in the sector. This change is supported by a growing range of technologies and energy service options such as storage and smart consumption management, and emergence of new business models in the competitive retail market. It is important that this change happens in an efficient, secure and reliable energy system that keeps prices as low as possible.

In a deeply connected energy sector, the impact of these changes is not confined to one part of the energy sector, and indeed the energy sector itself. The changes link the electricity and gas markets, and importantly energy and environmental policy. The Commission's work program[2] has and is contributing to these changes in key areas by establishing and recommending frameworks that are in the long-term interests of consumers. These key areas are:

- the integration of energy and emissions reduction policy
- redesigning the east coast gas markets to free up gas trading
- promoting systems security as the market transitions to new technologies and renewables
- enabling the competitive energy services market.

1 A copy of the terms of reference can be found on the Commission's website. This can be found at www.aemc.gov.au/Markets-Reviews-Advice/Electricity-Network-Economic-Regulatory-Framework

2 More detail on the Commission's key projects can be found in the 2015-16 Work program overview. This can be found at http://www.aemc.gov.au/getattachment/d253a27d-cc1e-4dc8-9bd3-ed5e629db2a2/AEMC-Year-in-Review-2015-2016.aspx

Against this background of change, it is important that the economic regulatory framework remains robust and flexible, and continues to support the efficient operation of the energy market in the long term interest of consumers.

This annual review is part of the Commission's work to support the continual evolution of the energy sector. The Commission will use the review as a platform to monitor changes in the market and, where necessary, consider the need for the economic regulatory framework to respond.

The economic regulatory framework for electricity networks

Defining the framework

Prior to reviewing the operation of the economic regulatory framework, it is useful to first describe what the framework entails and the principles by which it operates. The National Electricity Law (NEL) and the National Electricity Rules (NER) set out the economic regulatory framework governing electricity networks. Chapter 6 and Chapter 6A of the NER cover economic regulation of distribution and transmission services. Chapter 5 of the NER (connection and planning arrangements) and jurisdictional instruments such as reliability standards also impact on how the provision of network services is regulated. The NEL and the NER also set out, amongst other matters, the role of regulatory bodies as well as the process for the review of regulatory decisions.[3]

Why regulate?

Electricity networks are capital intensive and incur declining average costs as output increases. Network services in a particular geographic area are therefore most efficiently provided by one supplier. As there is no competition, providers of network services[4] are regulated to encourage efficient investment and maintenance of the electricity network, and to prevent consumers from being overcharged for its use.

Key principle of economic regulation of network service providers (NSPs)

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 locking in NSPs' revenue allowances prior to each regulatory control period. With revenue locked in, NSPs are incentivised to provide services at the lowest possible cost because their returns are determined by their actual costs of providing services. If NSPs reduce their costs to below the estimate of efficient costs, the savings are shared with consumers in future regulatory periods. Since NSPs are incentivised to provide services efficiently, they are provided with discretion to choose how they provide network services.

3 A detailed discussion of the economic regulatory framework for electricity networks is in chapter 2 of this report.

4 Distribution network service providers (DNSPs) and transmission network service providers (TNSPs)

The Commission's approach in reviewing the economic regulatory framework

In reviewing the operation of the economic regulatory framework, the Commission has been guided by the principles of economic efficiency as it is a central element of the national electricity objective (NEO). These principles are expressed in the following questions:

- Does the economic regulatory framework provide the right incentives to network businesses to produce services at lowest cost?[5]
- Is an appropriate mix of network and non-network services being produced and consumed?[6]
- Is the economic regulatory framework flexible enough such that the above outcomes can continue to be achieved over time?[7]

The Commission has gathered information and consulted stakeholders in order to provide a foundation for further analysis of these questions in future editions of this report. How the framework has evolved so far to a changing market and key areas for further monitoring and analysis are set out below.

The framework has evolved and adapted to changes

The NEL contains a provision that allows the Commission to make a rule at the request of any person[8] so long as it is within the Commission's rule making power[9] and the issue falls within the subject matter for the NER[10]. This provides a mechanism so that the framework can respond to issues and changes (both technical and economic) raised by the stakeholders.

In reviewing the regulatory framework, the Commission considered major issues that impact on the provision of network services and how the economic regulatory framework has responded to them. These issues include:

- system security
- coordination of transmission and generation investment
- new technologies, increase in decentralised generation, growth in energy management services
- rising network costs and concerns about under-utilisation of assets.

5 This is known as productive efficiency.

6 This is known as allocative efficiency.

7 This is known as dynamic efficiency.

8 See section 91(1) of the NEL. This provision also provides for the MCE (predecessor of the COAG Energy Council) and the Reliability Panel to submit rule change request.

9 The Commission's rule making power is in section 34 of the NEL

10 See Schedule 1 of the NEL.

System security

The shift in the generation fleet in the NEM driven by climate change and renewable energy policies and technological advances is changing the energy landscape. The NEM is transitioning from one powered by coal, gas and hydro to being powered increasingly by renewable sources such as wind and solar. This change in generation technology has altered the operational dynamics of the power system and the need for system services to be able to keep it secure.

In response to this shift, the Commission initiated the *System security market frameworks review* in July 2016 to consider changes to the regulatory frameworks to support the current shift towards new forms of generation in the NEM. The focus of the review has been on addressing priority issues to allow the Australian Energy Market Operator (AEMO) to continue to maintain power system security as the market transitions.

The final report for the *System security market frameworks review* was published in June 2017 and implementation of its recommendations will lead to:

- a stronger system
- a system better equipped to resist frequency changes
- better frequency control
- action to further facilitate the transformation.

The *System security market frameworks review* is part of the Commission's system security work program which also includes five rule change requests received on related matters. These rule change requests have been progressed concurrently and in coordination with the review. Final rules have already been made for two of these proposals, with new arrangements for under- and over-frequency control schemes being introduced on 6 April 2017.

Further details on the *System security market frameworks review* recommendations and the related rule change requests can be found on the Commission's website[11].

Coordination of transmission and generation investment

The change in generation mix has raised an important issue on how, and whether, generation and transmission investment is efficiently co-ordinated. Historically, the consequences of whether or not transmission and generation investment was coordinated were less material, but this is likely to change going forward as the shape of the transmission network may need to change to reliably supply consumers from a different generation mix. The Commission is currently analysing this issue through its *Reporting on drivers of change that impact transmission frameworks review.*

11 Go to http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review#

Under the existing NEM frameworks:

- Generation investment is determined by market participants on the basis of market signals: expectations of future spot prices and retailers' willingness to enter into contracts to hedge against future price risk. Investment in generation assets in the NEM is intended to be market-driven taking into account - amongst other things - expectations of future demand, the location of the energy source, access to land and water and proximity to transmission infrastructure.
- TNSPs are responsible for making investment decisions, in accordance with their planning activities (set out below). TNSPs must make investments in order to meet the relevant jurisdictional reliability standard. Any investments made by TNSPs are funded from revenue received from consumers. TNSPs are also permitted, but not obliged, to undertake capital expenditure to reduce congestion - within their own region or between two regions - when this passes the RIT-T.

The differences in generation and transmission investment decision making processes have the potential to result in a development path that does not minimise the total system costs faced by consumers.

The Commission’s *Reporting on drivers of change that impact transmission frameworks review* provides analysis on a set of drivers that influence the co-ordination of transmission and generation investment. The reporting regime is a two stage process. Stage 1 of the review has examined whether these identified drivers have changed significantly, whether there is an environment of major transmission and generation investment and whether this investment is uncertain in its technology or location. The Commission considers that conditions have been met such that this reporting should progress to the second stage. Stage 2 of this review will undertake a thorough examination of the coordination issues related to transmission and generation, and what improvements could be made to the current regulatory arrangements to ameliorate these issues.

The Commission’s final stage one report was published on 18 July 2017, with this containing the Commission’s decision to proceed to Stage 2. The Commission is scheduled to publish an approach paper for Stage 2 in August 2017, which will set out our approach to the Stage 2 along with indicative timings.

Further details about this review can be found on the Commission’s website.[12]

New technologies, increase in decentralised generation, growth in energy management services

Technology surrounding the grid is changing. In recent years, more and more consumers have been adopting decentralised energy resources. New forms of generation, including solar PV and battery storage, are becoming cheaper and better - and as a consequence, more widespread and viable at a small scale. At the same time technological innovation is allowing for resources to be deployed and co-ordinated in

12 Go to http://www.aemc.gov.au/Markets-Reviews-Advice/Reporting-on-drivers-of-change-that-impact-transmi

unprecedented ways, giving rise to new forms of monetisation, trade and ownership. The technological innovation also means that NSPs now have a much more diverse range of solutions (commonly referred to as non-network solutions) compared to the traditional network options.

Under incentive regulation, it is not the role of the regulatory framework to determine what the ideal or efficient level of uptake of non-network solutions should be. Rather, the current framework provides a number of incentives and obligations for non-network options to be adopted where it is efficient to do so. For example:

- **The regulatory investment tests for distribution and transmission (RIT-D and RIT-T).** The RIT requires DNSPs and TNSPs to assess the costs and benefits of each credible investment option to address a specific network problem to identify the option which maximises net market benefits (or minimises costs where the investment is required to meet reliability standards).[13]
- **Demand management incentive scheme (DMIS) and Demand management innovation allowance (DMIA).** The DMIS provides DNSPs with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management. The scheme will reward DNSPs for implementing relevant non-network options that deliver net cost savings to retail customers. The DMIA provides DNSPs with funding for research and development in demand management projects that have the potential to reduce long term network costs. The allowance will be used to fund innovative projects that have the potential to deliver ongoing reductions in demand or peak demand.

The Commission's research and discussions with stakeholders have highlighted a number of case studies where stakeholders have leveraged the incentives under the current regulatory framework for the use of non-network solutions. Some of these examples include:

- South Australia Power Networks' and AusNet's (separate) trials of large scale battery storage
- Reposit's energy management software
- the deX platform for the trading of decentralised energy resources.

In addition to existing incentive mechanisms, substantial reforms to network regulation have and continue to be made arising out of the Commission's Power of Choice review. Power of Choice focussed on putting consumers at the centre of the regulatory system by giving them the information they need to choose the products and services they want at the prices they are willing to pay.

One significant Power of Choice reform that the Commission has implemented is the *Expanding competition in metering and related services* rule change. The final determination

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13 TNSPs are required to quantify market benefits where they are material under the NER, whereas DNSPs may quantify market benefits where these are material. See NER clauses 5.16.1(c)(5) and 5.17.1(d).

was published in November 2015 and put in place a competitive framework for providing metering and related services to retailers and customers, expanding competition in metering and related services. The final rule provided a clear and open framework for the contestable supply of services from advanced meters to retailers and customers. This is important as electricity meters are no longer the simple total energy use measurement tool for networks that they used to be. Instead, they can assist the supply of a variety of products and services which consumers value and can be provided by any business with the skills and motivation to do so.

Currently, the Commission is considering two rule changes on the contestability of energy services from the COAG Energy Council and Australian Energy Council. These rule change requests related to which services should be economically regulated. In particular, COAG Energy Council seeks to reinforce the principle that only services which exhibit natural monopoly characteristics should be economically regulated. The AEC rule change also seeks to introduce contestable frameworks for some of the inputs (e.g. network support) that DNSPs use in providing economically regulated services.

Rising network costs and concerns about under-utilisation of assets

The cost of producing network services had been increasing in all jurisdictions over the past ten years. Apart from increase in cost, the growth in regulatory asset bases, coupled with flatlining or declining demand have led to declining utilisation rates and concerns about stranded assets.

In response to concerns about utilisation rates, the Commission has made a number of rule changes recently to incentivise NSPs to operate more efficiently. Some of these rule changes include:

- **2012 economic regulation of network service providers rule change**. This gave the AER greater flexibility over how network revenues and prices are determined. The rule change also required the AER to publish annual reports on the relative efficiencies of electricity network businesses. This provides public information on the relative performance of the NSPs. Under this rule change, the AER provided a significantly lower level of revenue compared to the NSPs' proposal in the 2013-15 round of revenue determinations.
- **Introduction of the capital expenditure efficiency sharing scheme (CESS).** The CESS was introduced as part of the 2012 economic regulation of network service providers rule change. The CESS encourages NSPs to make efficient capital investment decisions, as well as balancing the incentives between achieving operating and capital expenditure efficiencies.
- **2014 distribution network pricing arrangements rule change.** This was the second significant rule change resulting from the Power of Choice review. The Commission made a new rule requiring DNSPs to set network prices which reflect the efficient costs of providing network services. This will allow consumers and their agents to compare the value they place on using the network against the costs caused by their use of it, and make decisions accordingly. Network prices based on the new pricing objective are being phased in from 2017.

- **2015 demand management incentive scheme rule change.** The rule is designed to complement existing arrangements that encourage NSPs to consider non-network options where it is efficient to do so, and regardless of whether the options are provided by the NSPs or third parties. The rule also provides for a separate allowance (demand management innovation allowance) to fund research and development in demand management projects that have the potential to reduce long term network costs.

Areas of focus for future reports

Through the Commission's own analysis as well as consultation conducted as part of the review, the Commission has identified a number of areas that warrant continued monitoring or further investigation. These areas are:

- NSPs' financial incentives in delivering economically regulated services
- continual implementation of pricing reform
- the changing role of distribution networks, as outlined in the Commission's work on the distribution market model project.[14]

The Commission will also consider the co-ordination of generation and transmission investment through the biennial reporting regime, *Reporting on drivers of change that impact transmission frameworks*.

NSPs' financial incentives in delivering economically regulated services

Though recent and ongoing changes to the economic regulatory framework have sought to strengthen incentives to NSPs to seek alternatives to traditional network solutions, some stakeholders remain concerned about biased incentives for NSPs to prefer capital expenditure. In response to this concern, for the 2018 edition of this report the Commission will review the financial incentives that network businesses face in delivering economically regulated services under the existing regulatory framework. This analysis will be particularly focussed on the financial incentives network businesses face to deliver their regulated services using distributed energy resource based solutions relative to traditional network solutions.

The analysis would include assessments of the incentives network businesses face to undertake:

- capital or operating expenditure service delivery methods
- long or short asset life service delivery methods
- network or non-network service delivery methods
- in-house or third party service delivery methods.

14 http://www.aemc.gov.au/Markets-Reviews-Advice/Distribution-Market-Model

The Commission will also examine frameworks that overseas regulators have adopted as a result of findings that their previous regulatory frameworks did not provide balanced incentives for service delivery methods. This will include the total expenditure based frameworks adopted in the United Kingdom for electricity, gas and water regulation. Under these frameworks the distinction between capital and operating expenditure (both in assessment and recovery method) is removed.

Continual implementation of network pricing reforms

An area of reform that has significant potential to improve incentives to allocate resources efficiently between network and non-network solutions and reduce future network capex is network pricing reform. Currently, the cost of augmenting the network to deal with a local constraint is shared between all customers of the DNSP. Prices for network services therefore do not necessarily reflect the actual cost of producing those services, but an average across the network area.

In addition to establishing new pricing objectives, the 2014 *Distribution network pricing arrangements* rule change also introduced new processes and timeframes for setting network prices and requires distribution network businesses to consult with consumers and retailers to develop a tariff structure statement (TSS) that outlines the price structures that they will apply for the regulatory period.

The first TSS period, which is from 2017 to 2019, has seen NSPs introducing demand based or time-of-use tariffs that better reflect the cost of the networks, albeit generally on an ‘opt-in’ basis.

It is important that NSPs build upon their current work in the next TSS period starting in 2019. The implementation of cost reflective pricing will create the essential foundation for future reforms, including potentially more advanced pricing options such as dynamic and locational pricing in the future.

The Commission also considers network pricing reform as a prerequisite to a well-functioning and competitive energy services market and will monitor its implementation in future reports. Cost reflective pricing not only provides a signal to consumers of electricity, but also facilitates development of services that assist consumers in optimising their energy usage and sends an investment signal to distributed energy resource providers.

The changing role of distribution networks – distribution market model project

Historically, the development of distribution networks, and the regulatory arrangements that underpin them, have been focused on distribution network businesses providing sufficient network capacity to meet increasing consumer demand while maintaining the safety, reliability and security of electricity supply.

However, in light of the increasing uptake of distributed energy resources and the range of services they are capable of providing, distribution system operations and associated regulatory arrangements are likely to require greater consideration of three other issues: the value of optimising investment in and operation of distributed energy resources, the value of coordinating the operation of distributed energy resources with the wholesale market, and, more broadly, what should be regulated and what should be delivered by competitive markets.

The Commission has therefore initiated an internal research project to explore the key characteristics of a potential evolution to a future where investment in and operation of distribution energy resources is optimised to the greatest extent possible and where there is greater coordination of the operation of distributed energy resources with other markets.

The Commission considers that promoting the development of a competitive distribution market for the provision of services enabled by distributed energy resources means that markets, in response to consumer decision-making, determine the most efficient outcome. As a general rule, the best outcomes are achieved when consumers make choices based on their own interests or values, thus driving investment and deployment of particular technologies.

In the Commission's view, such a market can develop where there is a level playing field for the provision of 'optimisation' services. A level playing field means that any party taking on the optimising function is independent from network provision and exposed to financial incentives. This means that regulated network businesses should not take on an optimising function because they are not independent of the provision of certain services, i.e. network services.

The draft report for the *Distribution Market Model* project was published on 6 June 2017. Stakeholders submission closed on 4 July and the Commission is expected to publish the final report in August 2017. Future reports of this review will provide a platform for the Commission to continue examination of the development of a competitive distribution market.

Contents

1 About this review

The Australian Energy Market Commission (Commission) has completed the first review on the electricity network economic regulatory framework. This review was conducted under the standing terms of reference set by the COAG Energy Council. This is available on the project page on the Commission's website.[15] The Commission is required to publish its finding annually.

1.1 Purpose of the review

This annual review is part of the Commission's work to support the continual evolution of the energy sector. The Commission will use the review as a platform to monitor changes in the market. The review will also allow the Commission to identify changes where necessary so that the economic regulatory framework remains robust, flexible and continues to support the efficient operation of the energy market in the long term interest of consumers.

1.2 Context of the review – a sector in transition

The energy sector is undergoing significant change. The national electricity market (NEM) is moving from predominantly large-scale centralised generation to greater amounts of smaller, distributed and intermittent generation. At the same time, households and businesses are changing the way they use electricity and how they engaged with participants in the sector. This change is supported by a growing range of technologies and energy service options such as storage and smart consumption management, and emergence of new business models in the competitive retail market. It is important that this change happen in an efficient, secure and reliable energy system that keeps prices as low as possible.

In a deeply connected energy sector, the impact of these changes is not confined to one part of the energy sector, and indeed the energy sector itself. The changes link the electricity and gas markets, and importantly energy and environmental policy. The Commission's key areas of work[16] are structured to address this increasing connectedness:

- the integration of energy and emissions reduction policy
- redesigning the east coast gas market to free up gas trading
- promoting systems security as the market transitions to new technologies and renewables
- enabling the competitive energy services market.

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15 www.aemc.gov.au/Markets-Reviews-Advice/Electricity-Network-Economic-Regulatory-Framework

16 More detail on the Commission's key projects can be found in the 2015-16 Work program overview. This can be found at http://www.aemc.gov.au/getattachment/d253a27d-cc1e-4dc8-9bd3-ed5e629db2a2/AEMC-Year-in-Review-2015-2016.aspx

1.3 Approach

1.3.1 Overall approach

Consumer choices will continue to shape the future development of the electricity market. It is not possible to know whether certain scenarios will prevail and it is not the Commission's role in conducting this review to predict exactly how the market is likely to develop in the future. This review has focussed on the key features the economic regulatory framework requires to enable it to meet future challenges, whatever they may be.

The Commission has also taken a holistic approach in preparing this report so that it examines the economic regulatory framework for electricity networks as a whole. This report has drawn on and referred to work or reforms already underway and assessed whether the regulatory framework is capable of continuing to promote the NEO.

The Commission has used the first report to review the operation of the economic regulatory framework, how it has evolved against the backdrop of change in the past decades and identified areas that may require further investigation in future reports. As the first report of the annual review, the 2017 report provides a foundation for assessing the performance of the framework, rather than recommending changes.

1.3.2 Approach paper, stakeholder consultation and market monitoring

Approach paper

The Commission published an approach paper on the review on 1 December 2016. The approach paper invited stakeholders to provide submission and comment on the Commission's proposed approach in conducting the review. Submission to the approach paper closed on 2 February 2017 and the Commission received nine submissions, which are available on the Commission's website.[17] Stakeholders' comments in the submissions have informed the Commission's review, and are discussed and referred to in this report where relevant.

Stakeholder consultation

As part of the review process, the Commission consulted with a variety of stakeholders. These stakeholders include distribution network service providers (DNSPs), transmission network service providers (TNSPs), market bodies such as the Australian Energy Regulator (AER), the Australian Energy Market Operator (AEMO) and Energy Consumer Australia (ECA), industry bodies such as Energy Networks Australia (ENA) and the Australian Energy Council (AEC) and energy startups such as Reposit Power.

17 www.aemc.gov.au/Markets-Reviews-Advice/Electricity-Network-Economic-Regulatory-Framework

Market monitoring

In addition to formal consultation, Commission staff also attended a number of industry forums and workshops.[18] These workshops provided valuable first hand insight to the Commission on technological developments in the energy sector as well as issues faced by the industry in general.

In preparing this report, the Commission has also taken into account submission and feedback received during consultations on other reviews or rule change requests.

1.4 Structure of this report

The remainder of this report is structured as follows:

- chapter 2 sets out the existing economic regulatory framework for network service providers
- chapter 3 provides an overview of the change in the usage pattern of the electricity grid and how network service providers have responded to the change
- chapter 4 details the Commission's review of the economic regulatory framework and issues that require investigation in future reports.

18 Examples of these forums and workshop include ones held by ENA, the Clean Energy Council, forums showcasing new energy technologies as well as workshops facilitated by new energy service providers.

2 The economic regulatory framework for electricity network service providers

Box 2.1 Summary

- Electricity networks are capital intensive and incur declining average costs as output increases. Network services in a particular geographic area are therefore most efficiently provided by one supplier.
- As there is no competition, providers of network services (i.e. DNSPs and TNSPs) are regulated to encourage efficient investment and maintenance of the electricity network, and to prevent consumers from being overcharged for its use.
- 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 locking in NSPs' revenue allowances prior to each regulatory control period. With revenue locked in, NSPs are incentivised to provide services at the lowest possible cost because their returns are determined by their actual costs of providing services. If NSPs reduce their costs to below the estimate of efficient costs, the savings are shared with consumers in future regulatory periods.
- Since NSPs are incentivised to provide services efficiently, they are provided with discretion to choose how they provide network services.
- The AER uses the building block methodologies set out in Chapters 6 and 6A of the NER to calculate each NSP's total revenue allowance. This includes estimates of capital expenditure, operating expenditure, a rate of return and an allowance for tax.

In order to assess the effectiveness of the economic regulatory framework, it is necessary first to describe what the framework entails and the principles by which it operates. This Chapter sets out the existing framework for network service providers. The framework is broken down into:

- Why is network regulation required and what is its purpose?
- Key institutions, roles and scope
- What services are economically regulated?
- How are services economically regulated?
- What regulations apply to services not economically regulated?
- Recent regulatory reforms

The majority of this Chapter focuses on the regulatory framework for DNSPs. However, where issues related to distributed energy resources arise for TNSPs that are different to DNSPs this is also highlighted.

2.1 Why is network regulation required and what is its purpose?

Electricity networks are capital intensive and incur declining average costs as output increases. Network services in a particular geographic area are, therefore, most efficiently provided by one supplier. For example, the cost of transporting electricity from generators to households would be much higher if two or more businesses built competing poles and wires in one area. This is what is known as a natural monopoly market structure.

As there is no competition, NSPs are regulated to encourage efficient investment and maintenance of the electricity network, and to prevent consumers from being overcharged for its use.

The framework also provides requirements for NSPs to meet numerous regulatory standards relating to the safety, reliability and security of electricity supply.

Box 2.2 System security

The Commission recently published the *System Security Market Frameworks Review* which was used to consider, develop and implement changes to the market rules to allow the continued uptake of new forms of generation while maintaining the security of the system.

Currently, Chapters 6 and 6A enable the AER to set the maximum revenues that may be earned and prices charged by electricity network service providers to deliver electricity to customers. These sections relate to the setting of revenues for NSPs. The Commission considers that the regulatory framework needs to be sufficiently flexible to facilitate and keep up with the pace of this transition across all parts of the NEM.

Acknowledging this, the Commission recently published a draft rule and draft determination on the *Managing the rate of change of power system frequency* rule change request. The draft rule places an obligation on transmission network service providers to provide minimum required levels of inertia to allow the power system to be maintained in a secure operating state.

The Commission considers that the provision of inertia by transmission network service providers would offer certainty that the minimum required levels would be made available, either through investment in network equipment or by contracting with third party providers. Under network regulation arrangements, transmission network service providers have financial incentives to minimise the costs associated with meeting their obligations. They would also have the ability to coordinate inertia provision with the more locational requirements of maintaining system strength.

The Commission also published a draft rule and draft determination on the *Managing power system fault levels* rule change request. The main feature of the draft rule provides an enhanced framework that requires network service providers to maintain the system strength at generator connection points above an agreed minimum level, under a defined range of conditions. This builds on the existing arrangements for generators to meet their registered performance standards. The enhanced framework is technology neutral and requires the network service provider to use existing planning and regulatory arrangements when acquiring or providing services to assist in the maintenance of system strength above the registered levels.

2.2 Governance and scope of the regulatory framework

Table 2.1 Relevant institutions involved in electricity network regulation

	COAG Energy Council	**State and territory governments**	**AEMC**	**AER**	**Australian Competition Tribunal**	**Federal Court of Australia**
Function	The Energy Council is made up of federal, state and territory energy ministers. It provides national leadership on energy policy development and changes to the national electricity, gas and energy retail laws and regulations.	Each state and territory government has control over how transmission and distribution reliability standards are set, and the level of reliability that must be provided by NSPs. Jurisdictional governments are also able to apply specific obligations within their states. For example, in Queensland, South Australia and Tasmania DNSPs must charge the same prices for all residential consumers regardless of their location within the network.	The AEMC makes the national electricity, gas and energy retail rules, and advises the COAG Energy Council on energy market development. The AEMC can generally only amend a rule if requested to do so by another person.	The AER performs the economic regulatory, compliance and enforcement functions in the national electricity, gas and energy retail markets. The AER's role includes determining the regulated revenues for electricity and gas network businesses.	The Tribunal reviews decisions made by other administrative bodies, including decisions made by the AER about electricity and gas network businesses' regulated revenues. The Tribunal may in certain circumstances affirm or vary the AER's decision, or remit the matter to the AER to consider it again in accordance with any direction from the Tribunal.	In addition to merits review, the AER's decisions may be subject to judicial review by the Federal Court of Australia. The grounds for judicial review differ from merits review in that they relate to the legality of the administrative decision (e.g. an error of law), not the merits of the decision. Decisions by the Australian Competition Tribunal may also be subject to judicial review by the Federal Court of Australia. The Federal Court's decision may, in

	COAG Energy Council	State and territory governments	AEMC	AER	Australian Competition Tribunal	Federal Court of Australia
						certain circumstances, be appealed in the High Court of Australia.
Legislation and key instruments	The COAG Energy Council is established under an agreement between the federal, state and territory governments: the Australian Energy Market Agreement.	State and territory governments impose reliability standards and other obligations under jurisdictional legislation and legal instruments.	The AEMC's rule making powers in respect of the NER are exercised in accordance with national laws that are enacted in South Australia and adopted by each other participating jurisdiction through application acts: the National Electricity Law (NEL) set out in the National Electricity (South Australia) Act 1996 (SA).	The AER has functions and powers under the NEL and the National Electricity Rules.	The Australian Competition Tribunal is governed by the Competition and Consumer Act 2010 (Cth).	The AER's determination are subject to judicial review under the Administrative Decisions (Judicial Review) Act 1977 (Cth).

2.3 What services to regulate?

The first question within the network regulatory framework is to determine which services to economically (price/revenue) regulate, which services should be subject to a negotiate/arbitrate framework (negotiated services) and which services to leave to contestable service provision. For DNSPs, this question is answered by the AER through a process known as distribution service classification. The AER sets out the different services that DNSPs are likely to provide in the upcoming distribution determination and then determines if they will be economically regulated.

The NER guide the AER in making these decisions by providing factors the AER must take into account, such as the presence of barriers to entry in providing the service, and the presence of substitutes for the service. Generally speaking, the AER's approach to applying the factors has been to not economically regulate services with a greater degree of competition or potential for development of competition. Services with limited scope for competition are then subject to economic regulation. For TNSPs, the rules specify which services are economically regulated and which are negotiated services.

2.4 How are services economically regulated?

With the services to be economically regulated defined, the next question within the regulatory framework is how to regulate those services. This section addresses that question in detail in four parts:

1. The principles underlying network regulation in the NEM;
2. The building block approach to calculating revenue allowances for DNSPs;
3. The planning framework for DNSPs; and
4. The pricing framework for DNSPs.

2.4.1 Principles

The key feature of economic regulation of DNSPs in the NEM is that it is based on incentives. The AER locks in the total revenue requirement for each DNSP at the start of each regulatory period. It is based on the AER’s estimate of the efficient costs that a NSP would incur to meet its reliability standards and other regulatory obligations.

If a DNSP spends less than the estimated efficient cost, it will retain the difference for the remainder of the regulatory control period and then share the savings with consumers in the following regulatory control periods. This incentivises DNSPs to operate more efficiently and reduce costs. Conversely, if the DNSP spends more than the estimated efficient costs, it will not be allowed to recover the additional spending during the remainder of the regulatory control period.

Importantly, under this approach, the AER does not approve funding for DNSPs' specific projects or programs. Rather, once total revenue is set, it is for the NSP to decide which suite of projects and programs are required to deliver services to consumers while meeting its regulatory obligations. For example, the framework provides DNSPs 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; and
- procuring inputs from third parties or investing in assets directly.

Incentive based regulation is contrasted to cost of service regulation, which simply allows network businesses to recover the actual costs they incur in providing network services. Cost of service regulation is common in parts of the United States. Under cost of service regulation, network businesses do not have an incentive to make efficiency improvements because they recover their total costs regardless of whether they were efficiently incurred. Under this model the regulator plays a greater role in approving and determining the efficient cost of each project. Consumers lose out under cost of service regulation because businesses have limited incentives to make efficiency improvements over time and therefore consumers do not share in efficiency gains from lower total costs in the future.

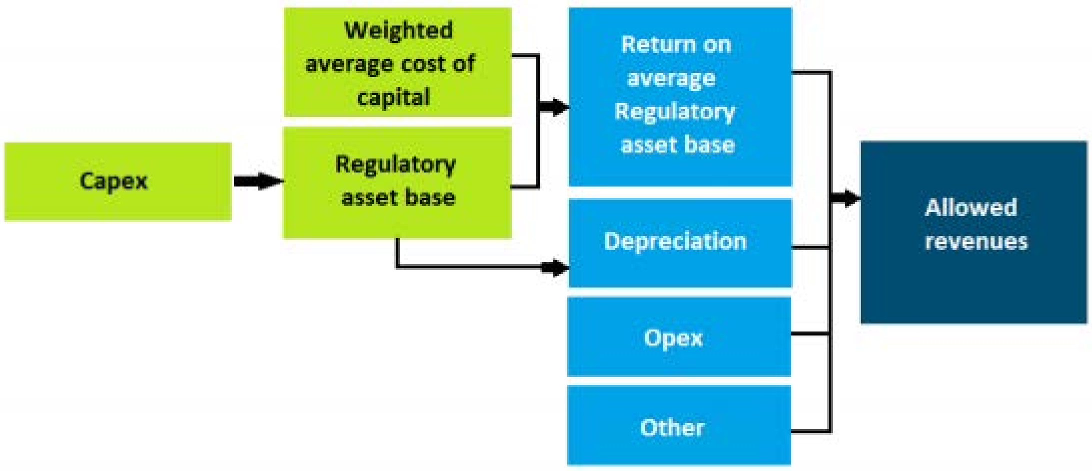
2.4.2 Building blocks

This section describes the following key components that are used to calculate NSPs' allowed revenues:

- Capital expenditure (Capex) - regulatory asset base, capital expenditure, weighted average cost of capital, depreciation and the role of jurisdictional reliability standards;
- Operating expenditure (Opex); and
- Other components - including corporate tax and the efficiency benefit sharing scheme.

These components form part of the building block framework, shown in Figure 3.1 below, that is used to calculate network businesses' allowed revenues.

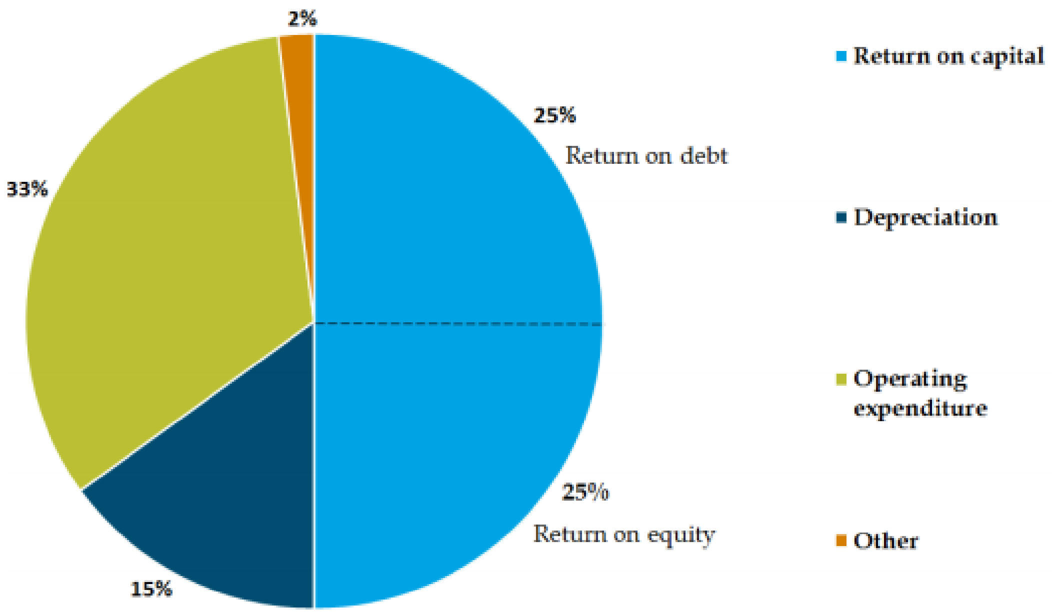
Figure 2.1 Components of the building block model



The breakdown of NSPs' allowed revenues into these building block components differs for each business, however Figure 3.2 provides a typical example. The largest component is typically the return on capital, which may account for up to two-thirds of revenue. The return on capital is determined by the size of a network's regulatory asset base (and forecast capital expenditure) and its weighted average cost of capital (the rate of return necessary to cover a commercial return on equity and efficient debt costs). Operating expenditure typically accounts for a further 30 per cent of revenue requirements.

Importantly, the AER does not approve specific projects or programs that NSPs are allowed to undertake under the building block approach. Rather, it estimates the total efficient costs of providing services over the entire regulatory period and it is for the NSP to decide which suite of projects and programs are required to deliver services to consumers in accordance with its regulatory obligations.

Figure 2.2 Example of typical breakdown of building block components



The treatment of capital expenditure

Capital expenditure is spent on buying and installing assets like poles, wires and other equipment that allows the network to convey energy to customers. It typically varies from year to year because capital assets are generally very costly to build but last for a number of years. To smooth out prices arising from the lumpy capital expenditure, the costs are recovered from customers over the life of the assets instead of at the time of investments.

The regulatory framework accounts for the difference between when a DNSP incurs capital expenditure and when it recovers these costs from consumers by allowing DNSPs to earn both a return on capital (rate of return multiplied by the regulatory asset base) and a return of capital (depreciation), both of which are recovered over the life of the assets.

Capital expenditure

The AER approves an estimate of total capital expenditure for each DNSP at the start of the regulatory control period. By locking in the allowance of efficient capital expenditure at the start of the regulatory control period, DNSPs face an incentive to undertake capital expenditure efficiently. This is because they keep savings on the financing costs of capital until the end of the regulatory control period if they spend less than their allowance. At the end of each regulatory period only the value of capital expenditure that was actually incurred by the DNSP is added to the regulatory asset base for the next regulatory control period, so any savings are therefore passed on to consumers through lower allowed network revenues (and, therefore, lower network charges) in future regulatory control periods.

The AER determines the total capital expenditure for the regulatory period based on the capital expenditure objectives and criteria set out in the NER. These objectives and criteria require the AER to determine the efficient costs a prudent network business would need to meet or manage estimated demand for standard control services, comply with regulatory requirements (including jurisdictional reliability standards) associated with providing standard control services and maintain safety of the distribution system through the supply of standard control services.

The AER is also required to, and has developed, an incentive scheme for capital expenditure under the NER, known as the capital expenditure sharing scheme (CESS). The CESS is not designed to replace the core feature of the economic regulatory framework of locking in total efficient capital expenditure up front. Rather, the CESS is complementary to this framework.

The AER highlights three purposes of the CESS:

- balance incentives to spend on capital and operating expenditure;
- equalise the incentive for efficient capital expenditure in each year of a regulatory period; and
- share efficiency gains and losses between DNSPs and consumers.

More detail on the CESS is set out in box 3.1 below

Box 2.2 The Capital Expenditure Sharing Scheme (CESS)

The CESS was introduced into the NER under the Commission's 2012 Economic regulation of network service providers final rule. The NER require that in developing a CESS, the AER take into account:

- that DNSPs should be rewarded or penalised for improvements or declines in efficiency of capital expenditure;
- that the rewards and penalties should be commensurate with the efficiencies or inefficiencies in capital expenditure;
- the interaction of the scheme with other incentives that DNSPs may have in relation to undertaking efficient operating or capital expenditure; and
- the capital expenditure objectives and, if relevant, the operating expenditure objectives.

The AER published its capital expenditure incentive guideline in November 2013. The guideline highlights that without a CESS a DNSP will face incentives that decline over a regulatory control period. For example, if a DNSP makes an efficiency gain in the first year of a five year regulatory control period any benefits will last for four more years before the regulatory asset base is updated for actual capital expenditure. In the final year, however, the benefit will be approximately zero. This may lead to inefficient capital expenditure and inefficient substitution of operating expenditure for capital expenditure towards the end of a regulatory control period.

The CESS is symmetric in that:

- a DNSP will retain 30 per cent of any underspend while consumers will receive 70 per cent of the benefit of an underspend; and
- a DNSP will also bear 30 per cent of the cost of any overspend, while consumers will bear 70 per cent.

Regulatory asset base

The regulatory asset base for a DNSP is the value of those assets that are used by the DNSP to provide standard control services, but only to the extent that they are used to provide such services. The AER determines the opening value of the regulatory asset base for DNSPs for each year of a regulatory control period.

In general terms, the regulatory asset base in a given year of the regulatory control period is based on:

- the value of the regulatory asset base at the end of the previous regulatory control period;
- depreciation within the regulatory period; and
- forecast capital expenditure within the regulatory period.

Return on capital

The value of the DNSPs' regulatory asset base is multiplied by the allowed rate of return to determine the return on capital.

The allowed rate of return, or the weighted average cost of capital, is the estimate of the cost of funds a DNSP requires to attract investment in the network. A good estimate of the rate of return is essential to promote efficient investment by DNSPs. If the rate of return is set too low, DNSPs may not be able to attract sufficient funds to be able to make required investments to maintain reliability and safety. Alternatively, if the rate of return is set too high, DNSPs may face an incentive to spend more than necessary and consumers will pay inefficiently high prices.

The rate of return also influences the incentives DNSPs face to spend on operating expenditure relative to capital expenditure. Capital expenditure earns a rate of return over time, whereas operating expenditure is recovered within the period of the expenditure. If DNSPs expect that the rate of return will be higher than their actual cost of capital (the cost of borrowing and shareholders' required return), they will be incentivised to undertake capital expenditure rather than operating expenditure.

Similar to the overall economic regulatory framework, the rate of return operates on an incentive basis. That is, the AER sets the rate of return at the start of the regulatory control period based on its estimate of the efficient financing costs of a benchmark efficient entity with a similar degree of risk as the DNSP. This provides DNSPs with an incentive to obtain financing at the lowest available cost because their returns are based on the estimated rate regardless of their actual financing costs during the period.

Box 2.3 Risk allocation principles

Under the incentive-based framework, the AER must set an allowed rate of return that reflects the efficient financing costs of a benchmark efficient entity. This benchmark entity must be subject to a similar degree of risk in providing regulated services as the NSP. The purpose of this approach is to maintain incentives for investment because investors can reasonably expect to recover efficient costs.

How each risk is allocated between NSPs and consumers is a key factor in the AER's determination of an appropriate allowed rate of return. The approach taken to risk allocation by the AEMC within the NEM is based on the principle that risks and accountability for investment decisions should rest with those parties best placed to manage those risks – generally the NSP that is making the business decisions. At the same time, measures that limit the risk imposed on NSPs to tolerable levels are likely to provide substantial benefits by limiting the allowed rate of return and resulting network tariffs.

Key factors affecting risk allocation

How demand risk is allocated between consumers and network businesses is important for the allowed rate of return. There are two common approaches:

- Revenue cap – the AER sets the allowed revenue a network business can recover over the regulatory control period

- Price cap – the AER sets the average price level that a network business can charge over the regulatory control period.

Tariffs are based on forecasts of future demand, consumption and customer numbers under both approaches. Under the revenue cap approach, average prices are adjusted each year for errors in forecasts that result in revenue recovery above or below the allowed revenue. Put simply, network businesses under a revenue cap are guaranteed to recover the allowed revenue over the regulatory period. Under a price cap approach, prices are not adjusted for errors in forecasts which result in revenue recovery above or below the allowed revenue.

Systematic variations (if any) in the allocation of risk under both approaches are reflected in the allowed rate of return by the AER.[19] The AER determines which approach is most appropriate for the network business in order to maximise benefits for end-users. Recent decisions have resulted in the AER moving to a revenue cap approach for network revenue determinations.

The allocation of demand risk is also closely related to reliability requirements and depreciation. For example, some stakeholders have suggested that the regulatory framework should allow for write downs of the Regulated Asset Base (RAB) if forecast demand that drives capital expenditure does not eventuate. This would be an unforeseen risk for NSPs that would increase the long term required rate of return on capital for future investors. As a result, asset write-downs on the RAB would require the AER to take into account this risk by increasing the NSPs' allowed rates of return. Consequently, short term benefits to current consumers would incur increased costs on future consumers.

Depreciation

Depreciation is the allowance provided so that capital investors recover their investment over the economic life of the asset (return of capital). The regulatory depreciation allowance is the net total of depreciation less the indexation of the regulatory asset base.

Operating expenditure

Operating expenditure is the non-capital cost of running the electricity network and maintaining the assets. Operating expenditure is generally recurrent and predictable from year to year.

Similar to capital expenditure, the regulatory arrangements for operating expenditure operate on an incentive basis. That is, the AER locks in an overall estimate of operating

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19 Note that investors can generally diversity away non-systematic, or business-specific risk. Therefore investors do not require financial compensation for business-specific risk. Financial compensation for equity holders is only required for bearing systematic risk. Sources of systematic risk include changes in real GDP growth, inflation, currency prices and real long term interest rates. See Australian Energy Regulator, Better Regulation - Equity Beta Issues Paper, October 2013, p8 for further discussion."

expenditure for each DNSP at the start of the regulatory period. This creates an incentive for DNSPs to undertake operating expenditure efficiently. This is because DNSPs retain savings for the remainder of the regulatory period if they spend less than the operating expenditure allowance. Consumers benefit where such savings have been made because the AER uses the information about costs incurred by the DNSP to set lower operating cost allowances for the next regulatory period.

The AER determines the estimated operating costs for the regulatory control period based on the efficient costs a prudent network business would incur. The NER provide the AER with discretion to use a range of methods and information to determine the efficient operating expenditure.

The NER require the AER to create an incentive scheme, known as the efficiency benefit sharing scheme (EBSS), for operating expenditure. Similar to the CESS, the objective of this is not to alter the incentive for efficient operating expenditure, as this is already embodied in the regulatory framework. Rather, the EBSS is complementary to this framework.

The AER highlights three purposes for the EBSS:

- provide a balanced incentive to reduce operating and capital expenditure;
- incentivise continuous efficiency improvements in operating expenditure throughout the regulatory period; and
- allow DNSPs and consumers to share in efficiency gains.

More detail on the EBSS is set out in box 3.2 below.

Box 2.4 The Efficiency Benefit Sharing Scheme (EBSS)

In developing and implementing an EBSS the NER require that the AER have regard to:

- the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs;
- the need to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure;
- the desirability of both rewarding DNSPs for efficiency gains and penalising DNSPs for efficiency losses;
- any incentives DNSPs may have to capitalise expenditure; and
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

The AER updated its EBSS in November 2013 at the same time as introducing the CESS. The AER considered the core aim of the EBSS is to provide a continuous incentive for DNSPs to pursue efficiency improvements in operating expenditure and to share efficiency gains between DNSPs and consumers.

The AER set out that the EBSS is intrinsically linked to its forecasting approach for operating expenditure. Where it is confident that a DNSPs' past operating expenditure is efficient, its preference is to use this as a base for forecasting future costs. In practice, under this approach it examines the actual operating expenditure a DNSP spent in one year of the regulatory period (the base year), and uses this to forecast operating expenditure needs for the next period. However, if this was applied without refinement, a DNSP would have an incentive to spend more operating expenditure in the year it expects the AER will use as a base for its next forecast. This is because spending more in the expected base year would make its future operating expenditure allowance larger.

The EBSS reduces the incentive a DNSP has to inflate its operating expenditure in the base year. It provides a continuous incentive for DNSPs to achieve efficiency gains. The combined effect of the revealed cost forecasting approach and the EBSS is that operating expenditure efficiency savings or losses are shared by 30 per cent to DNSPs and 70 per cent to consumers. For example, for a one dollar saving in operating expenditure the DNSP receives 30 cents of the benefit while consumers receive 70 cents of the benefit.

In contrast to capital expenditure, the allowance for forecast operating expenditure is recovered by DNSPs within the regulatory period. This also means that if a DNSP develops projects that require operating expenditure in multiple regulatory control periods, this expenditure must be proposed to the AER for each regulatory control period that the expenditure will occur in.

Other

The rules also provide for the AER to develop a Service Target Performance Incentive Scheme (STPIS) that provides rewards or penalties for network businesses based on how their reliability levels compare with historical performance. For example, if a network business' reliability performance worsens over time, it will be penalised by being allowed lower overall revenue. The amount of the reward or penalty is based on estimates of the value that consumers place on reliability.

The Commission published the Demand management incentive scheme final rule determination in November 2015. The final rule put in place a framework to require the AER to develop incentive schemes to encourage more efficient demand management expenditure decisions by DNSP. There are two mechanisms under the new framework:

- Demand management incentive scheme - the objective of the incentive scheme is to provide DNSPs with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management. The scheme will reward DNSPs for implementing relevant non-network options that deliver net cost savings to retail customers;
- Demand management innovation allowance – the objective of the innovation allowance is to provide DNSPs with funding for research and development in demand management projects that have the potential to reduce long term network costs. The allowance will be used to fund innovative projects that have the potential to deliver ongoing reductions in demand or peak demand.

The AER is currently consulting on the development of the demand management incentive scheme and innovation allowance.

2.4.3 Planning

Chapter 5 of the NER outlines provisions in relation to network planning and expansions.

The primary objective of this national planning framework is to establish a clearly defined and efficient planning process for network investment. Having such a framework in place supports the efficient development of a network, and provides transparency regarding network planning and investment activities. This enables market participants to make efficient investment decisions and provides a framework for network service providers to consider non-network alternatives to network investments.

Box 2.5 Co-ordination of transmission and generation investment

An important issue is how, and whether, generation and transmission investment is efficiently co-ordinated. Historically, the consequences of whether or not transmission and generation investment was coordinated were less material, but this is likely to change going forward as the shape of the transmission network may need to change to reliably supply consumers from a different generation mix. The Commission is currently analysing this issue through its *Reporting on drivers of change that impact transmission frameworks* review.

Under the existing NEM frameworks:

- Generation investment is determined by market participants on the basis of market signals: expectations of future spot prices and retailers' willingness to enter into contracts to hedge against future price risk. Investment in generation assets in the NEM is intended to be market-driven taking into account - amongst other things - expectations of future demand, the location of the energy source, access to land and water and proximity to transmission infrastructure.
- TNSPs are responsible for making investment decisions, in accordance with their planning activities (set out below). TNSPs must make investments in order to meet the relevant jurisdictional reliability standard. Any investments made by TNSPs are funded from revenue received from consumers. TNSPs are also permitted, but not obliged, to undertake capital expenditure to reduce congestion - within their own region or between two regions - when this passes the RIT-T.

The differences in generation and transmission investment decision making processes have the potential to result in a development path that does not minimise the total system costs faced by consumers.

The Commission's review provides analysis on a set of drivers that influence the co-ordination of transmission and generation investment. The review examines whether these identified drivers have changed significantly, whether there is an environment of major transmission and generation investment and whether this investment is uncertain in its technology or location. It is designed to assess whether changes that introduce more commercial drivers into transmission and generation development could be made to the frameworks, and so better promoting the coordination.

The Commission is undertaking the *Reporting on drivers of change that impact transmission frameworks* review in a two stage process. The Commission's final stage one report was published on 18 July 2017, with this containing the Commission's decision to proceed to Stage 2. The Commission is scheduled to publish an approach paper for Stage 2 in August 2017, which will set out our approach to the Stage 2 along with indicative timings.

Secondly, the framework is likely to assist the AER in performing its regulatory functions.

Two key components of the Chapter 5 planning arrangements in the NER are the requirements for DNSPs to undertake:

- a regulatory investment test (RIT-D) for projects to to address an identified need in its network where the possible expenditure exceeds a specified threshold; and
- an annual planning review and publish an annual planning report setting out the outcomes of the annual planning review (annual planning requirements).

These requirements are set out below.

Regulatory investment test

The NER contain specific requirements for DNSPs to undertake a RIT-D for major distribution projects. This is additional to the AER's assessment of efficient capital expenditure for the regulatory control period. Currently this is for projects where expenditure exceeds $5 million. This process is designed to test whether the DNSP has considered all credible options to address the need it has identified and the proposed investment is the most efficient solution (eg whether it is the most efficient way to meet the applicable reliability standards) and give providers of non-network solutions an opportunity to propose alternative approaches.

Under current arrangements DNSPs are not required to undertake a RIT-D for (amongst other reasons):

- unforeseen and urgent network investments to address network issues that would have an effect on reliability; and
- the maintenance, refurbishment and replacement of assets.

The AER's Replacement expenditure planning arrangements rule change request seeks to extend the application of the RIT-D (and RIT-T) to replacement projects. The AEMC published a draft determination on this rule change request on 11 April 2017. The draft rule proposed to extend the RIT-D and RIT-T to replacement expenditure.

Annual planning requirements

DNSPs must also annually review and report on the expected future operation of their networks over a forward planning period of at least five years. The review must involve:

- preparing maximum demand forecasts on different parts of the network;
- identifying limitations on the DNSP's network including those caused by the requirement for asset refurbishment or replacement;
- whether any corrective action is required to address these identified limitations; and
- take into account any jurisdictional electricity legislation.

DNSPs must set out the results of the annual planning review in a distribution annual planning report (DAPR). The DAPR is required to include information on:

- forecast loads on different parts of the network;
- forecast connection points, sub-transmission lines and zone substations;
- factors that may have an impact on its network including ageing and potentially unreliable assets;
- system limitations for sub transmission lines, zone substations and certain primary distribution feeders including options that may address these limitations;
- all committed investments (and alternative options that were considered) with an estimated capital cost of $2 million or more to be carried out within the forward planning period to address a refurbishment or replacement need, or an urgent and unforseen network issue;
- the DNSP's asset management approach; and
- other matters.

The final rule for the local generation network credits rule change requires DNSPs to publish information that is complementary to the DAPR a using a system limitation template prepared by the AER. This will include information on:

- the name or identifier and location of network assets where a system limitation or projected system limitation has been identified during the forward planning period;
- the estimated timing of the system limitation or projected system limitation;
- the proposed solution to remedy the system limitation;
- the estimated capital or operating costs of the proposed solution; and
- the amount by which peak demand at the location of the system limitation or projected system limitation would need to be reduced in order to defer the proposed solution, and the dollar value to the DNSP of each year of deferral.

2.4.4 Pricing

After total revenue is determined within each DNSPs' revenue determination, tariffs need to be developed to charge customers to allow NSPs to recover that revenue. It should be noted that customers are only exposed to network charges indirectly, through the retail price. There are two key components within the regulatory framework regarding network tariffs:

1. the control mechanism
2. rules regarding how each tariff is set - commonly known as pricing principles.

These two components are described below.

Control mechanism

There are two common approaches to the control mechanism:

- revenue cap – the AER sets the allowed revenue a network business can recover over the regulatory control period
- weighted average price cap – the AER sets the average price level that a network business can charge over the regulatory control period.

Prices are based on estimates of future demand under both approaches. Under the revenue cap approach, average prices are adjusted each year for errors in forecast demand and changes in specific prices that result in revenue recovery above or below the allowed revenue. Put simply, network businesses under a revenue cap are guaranteed to recover the allowed revenue over the regulatory period, but cannot recover more than that amount. Under the price cap approach, prices are not adjusted for errors in forecast demand or changes in specific prices which result in revenue recovery above or below the allowed revenue.

Under the NER, through the framework and approach process the AER determines which approach is most appropriate for DNSPs. In doing so the AER must have regard to a number of factors, including the need for efficient pricing structures, administrative costs and consistency with control mechanisms for other DNSPs. Currently, all of the DNSPs other than ActewAGL are regulated under revenue caps.[20]

Pricing principles

Substantial changes were made to the NER in the distribution network pricing arrangements rule change in 2014 regarding the pricing principles. A new pricing objective for distribution businesses was introduced requiring prices to reflect the efficient costs of providing network services to each consumer.

To achieve this objective, the new rule requires distribution businesses to comply with four pricing principles:

- Each network tariff must be based on the long run marginal cost of providing the service. If consumers choose to take actions that will reduce future network costs, such as by reducing peak demand, then they will be rewarded with lower network charges. Network businesses will have flexibility about how they measure long run marginal cost;
- The revenue to be recovered from each network tariff must recover the network business' total efficient costs of providing services in a way that minimises distortions to price signals that encourage efficient use of the network by consumers;[21]
- Tariffs are to be developed in line with a new consumer impact principle that requires network businesses to consider the impact on consumers of changes in

20 Unlike for DNSPs, the NER dictate that the control mechanism for TNSPs is a revenue cap.

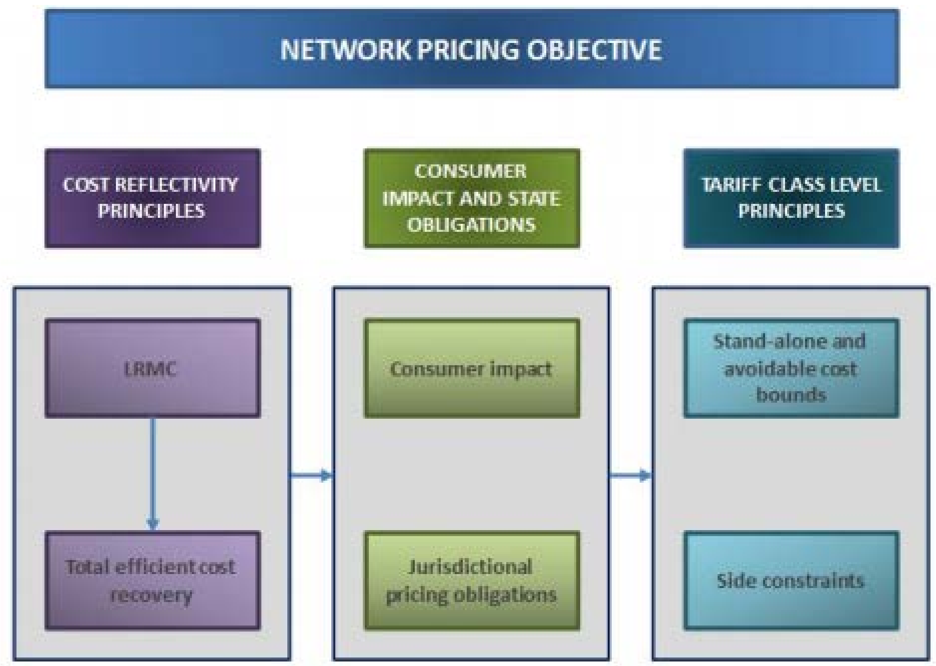
21 It should be noted that consumers only observe network tariffs to the extent that these are reflected in retail tariffs.

network prices and develop price structures that are able to be understood by consumers. Consumers are more likely to be able to respond to the price signals that network prices are designed to send if they can relate their usage decisions to network price structures and sudden price changes are avoided. Network businesses can gradually phase-in new price structures;

- Network tariffs must comply with any jurisdictional pricing obligations imposed by state or territory governments. But if network businesses need to depart from the above principles to meet jurisdictional pricing obligations, they must do so transparently and only to the minimum extent necessary.

The final rule and determination also clarify how the pricing objective and principles work together. Network businesses must comply with the principles in a way that contributes to the objective. If there is a conflict between the principles, the final rule specifies the order of priority of the principles and the extent of businesses' ability to depart from one of the principles to resolve that conflict. The relationship between the pricing objective and pricing principles is summarised in figure 3.3.

Figure 2.3 Distribution pricing framework



2.5 What regulations apply to services not economically regulated?

The sections above have set out which services will be economically regulated and how those services will be economically regulated. The last key question within the regulatory framework is what regulations apply when DNSPs seek to provide services which are not economically regulated. The arrangements for the separation of DNSPs' supply of economically regulated services from their supply of contestable services include ring-fencing, cost allocation and asset sharing provisions.[22]

22 For a detailed description of these arrangements see the Contestability of energy services consultation paper.

The purpose of these mechanisms is to provide an even playing field for all parties providing contestable services. They seek to prevent DNSPs from using regulated revenues, information gained from regulated service provision or their control of access to the shared network to gain an advantage in providing such services.

2.6 Regulatory reforms

The Commission's work program in recent years in relation to network regulation can broadly be split into three areas:

1. Flexibility and incentives;
2. Power of choice; and
3. Market structures.

These are described below.

2.6.1 Flexibility and incentives

In 2012 the Commission made significant changes to the network economic regulation rules. Of particular note, the changes gave the AER greater flexibility over the methods it uses to determine revenues.

The way the AER determines the return that network businesses can earn on their assets was of significant focus. Prior to 2012, the rules had set out a prescriptive approach to determining the rate of return, including line by line parameter estimates. The new rules replaced this with a focus on an overall objective – the rate of return is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk – and provide the AER with discretion within a guideline development process to establish a preferred approach to estimating the rate of return, in line with the objective.

The AER’s powers to undertake benchmarking were also clarified, removing the ambiguities regarding the AER’s ability to interrogate, review and amend capital expenditure and operating expenditure allowances based on benchmarking. To improve transparency and provide regular comparisons of network businesses the AER was also required to publish annual benchmarking reports on the relative efficiencies of electricity network businesses.

The reforms also provided the AER with new regulatory tools to strengthen and balance the incentive properties inherent in the framework. For example, the rules specifically provide for capital, operating and performance incentive schemes, but give the AER discretion in their form, strength and focus.

Similarly, the 2012 reforms gave the AER the ability to develop and apply small scale pilot or test incentive schemes that are not specifically provided for in the rules. These schemes would be applied within an environment that limits the amount of money at risk and the period that a scheme may operate. If successful, these schemes could then be incorporated into the system through rule change requests.

2.6.2 Power of choice

Substantial reforms to network regulation have and continue to be made arising out of our Power of Choice review. Power of Choice focussed on putting consumers at the centre of the regulatory system by giving them the information they need to choose the products and services they want at the prices they are willing to pay.

The distribution network pricing arrangements final rule published in 2012 was one major rule change completed out of Power of Choice. The AEMC completed the second major rule change resulting from the Power of Choice review – the expanding competition in metering and related services rule change. The final rule puts in place a regulatory framework to promote innovation and lead to investment in advanced meters that deliver services valued by consumers at a price they are willing to pay. Improved access to the services enabled by advanced meters will provide consumers with opportunities to better understand and take control of their electricity consumption and the costs associated with their usage decisions.

There are a number of other rule changes arising out of this work program which have been completed and that are relevant to network regulation. These include:

- Customer access to data;
- Demand management and embedded generation connection incentive scheme; and
- Embedded networks.

2.6.3 Market structures

The third area we have focussed on has been market structures. Networks are evolving from one-way energy delivery systems in a growth environment into multi-directional “smart grids”. In this environment a key question is where to draw the line between what is regulated, and what is not regulated – open to competition.

It is important to keep in mind in this discussion that our network regulatory framework attempts to replicate the incentives that businesses in competitive markets face. It does so to the extent possible, but it cannot replace the dynamic forces that competitive markets provide and the benefits that flow to consumers from such forces. It is therefore important that only those products and services where effective competition is unlikely to be possible, for example, those which supply contains natural monopoly characteristics, are regulated.

Furthermore, in instances where network businesses compete to provide products and services in unregulated, competitive markets, they should be required to do so on a level playing field. Put simply, regulated businesses should not be able to use their regulated revenues, the information they gain through regulated services, or their control of access to the network to gain an advantage in the supply of unregulated services.

Our recent and ongoing rule changes have focussed on this issue in a number of important areas:

- Expanding competition in metering and related services: By putting in place a competitive framework for providing metering and related services to retailers and customers, the expanding competition in metering and related services final rule provided a clear and open framework for the contestable supply of services from advanced meters to retailers and customers. This is important as electricity meters are no longer the simple total energy use measurement tool for networks that they used to be. Instead, they can assist the supply of a variety of products and services which consumers value and can be provided by any business with the skills and motivation to do so.
- Metering and embedded networks: required AER to put in place new national distribution ring-fencing guidelines by 1 December 2016, which the AER has done.
- Contestability of energy services: the Commission is currently considering two rule changes from the COAG Energy Council and Australian Energy Council related to which services should be economically regulated. In particular, COAG seeks to reinforce the principle that only services which exhibit natural monopoly characteristics should be economically regulated. The AEC rule change also seeks to introduce contestable frameworks for some of the inputs (e.g. network support) that DNSPs use in providing economically regulated services.
- Off-grid electricity supply; Western Power proposed a rule change request relating to distributors using off-grid supply models to supply customers with electricity. This seeks to remove what Western Power considers to be a regulatory barrier to distributors providing an off-grid supply to remote consumers instead of maintaining and/or replacing the network assets through which those consumers were previously supplied. Under Western Power's proposal the AER would be responsible for determining whether such supply is economically regulated or contestably provided.

3 The grid over time

3.1 Introduction

Trends in demand for electricity are undergoing a substantial and unprecedented shift. Demand is falling in both average and maximum terms, due to the greater uptake of decentralised energy resources and other factors. This has implications for the investment and operation of network businesses.

This chapter provides a summary of the Commission's research in the changing usage of the electricity system. Section 3.2 will described how demand is evolving, while section 3.3 will discuss how network businesses have responded to these trends.

3.2 Changing patterns of electricity use

3.2.1 Trends in demand

> "[In 2009] electricity supplied by [the NEM] reached an all-time high of 195.0 TWh. Then, over the following five years while the Australian economy grew by approximately 13 per cent, annual electricity consumption in eastern Australia declined by 7 per cent to reach 181.2 TWh in FY 2013-14."[23]

In 2009, absolute levels of energy consumption in the Australian economy fell for the first time in history. This was not forecast either by planning authorities or by participants in the market. Initially, this change was attributed to the global financial crisis. But as the economy rebounded, demand for electricity did not. As technology evolves and more and more households turned to decentralised generation - as well as increased energy efficiency and a decline in the manufacturing sector of the economy - regulators and stakeholders are now facing the prospect that the consumption of grid-supplied electricity in Australia will no longer be coupled to economic growth.[24]

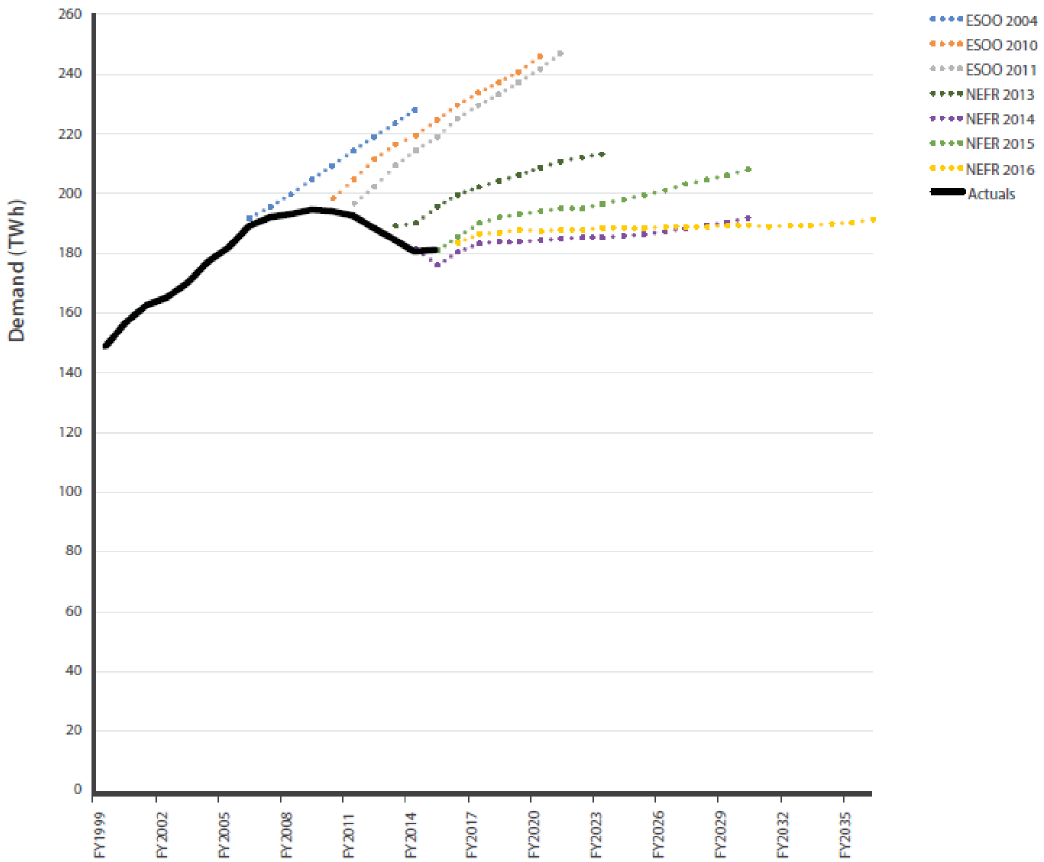
Figure 3.1 shows the dramatic divergence between forecast and actual energy demand, with the historical growth trend beginning to moderate in 2006-7 before actually reversing in 2009-10. It can be seen that AEMO has subsequently updated its forecasts to reflect that its expectations of demand have been revised downwards. AEMO's 2016 National Electricity Forecasting Report (NEFR) forecasts that consumption[25] is to remain flat over the next 20 years while demand is predicted to continue to decline.

23 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*, 2015.

24 Ibid

25 Consumption is the amount of electricity consumed from the grid over a period of time (as distinct from demand, which measures electricity use at a point in time).

Figure 3.1 Forecast versus historical energy demand



Source: AEMO data. Chart from the 'Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future', p. 135

A more detailed discussion of recent changing trends in demand, including patterns in the daily peak, can be found in Appendix A.1.

3.3 Trends in network investment

As the way the grid is used is changing, so too should the way network businesses operate and invest. This section will investigate the extent to which the historical trends described above are being reflected in network businesses' investment decisions.

The major components of network capital expenditure (capex) are augmentation and replacement expenditure (augex and repex respectively). Augex is defined as capital expenditure primarily required to increase the capacity of the network to allow for load growth.[26] Augex may also be undertaken to maintain quality, reliability and security of

26 AER, *Guidance Document: AER Capex model - data requirements*, p. 4. See https://www.aer.gov.au/system/files/AER%20model%20guide%20-%20Capex%20capex%20(augex)%20-%20draft%20expenditure%20forecast%20assessment%20guideline.pdf

supply in accordance with legislated requirements.[27] Repex is the non-demand driven replacement of an asset at the end of its economic life.[28]

As technologies evolve and network businesses become increasingly geared towards decentralised energy resources, as opposed to traditional centralised generation, it would not be unreasonable to expect the 'like-for-like' replacement of capital assets to decline. Holding other factors constant, this would be expected to result in falling repex values over time. The potential impact of these trends on capex expenditure is more ambiguous, and must be interpreted in light of trends in the demand for network services. As maximum demand declines, this would tend to reduce the need for augex which increases the network's capacity in order to meet an expected increase in load. However, technological change might also drive capex of the network to enable these additional services. For example, as more households generate energy on site and export it back to the grid, there might need to be investment in upgrading feeders to enable two-way flows of electricity.

It is important to re-emphasise the expectations above depend on *holding other factors constant*. In reality, this will not always be the case. Other relevant factors which drive investment trends will add statistical 'noise', which may obscure the true relationship between (say) demand and augex. For example, if over a particular time period significant augex is undertaken for the purpose of meeting a change in reliability standards, expenditure figures for that period may not show any correlation with demand. However, unless there is some systematic correlation between these external factors and trends in demand, over time a positive relationship between capex - particularly augex - and demand should still be observable.

The Commission will continue to monitor these indicators in future reports. Unless stated otherwise, all values in this section are in 2016 dollars.

3.3.1 Capex

Between 2009-2016, trends in overall capex have varied between jurisdictions. Tasmania, Queensland, South Australia and New South Wales have seen an overall decline in year-on-year expenditure over this period, although with the exception of Queensland the trend for these states between 2009-2012 was for capex to increase. Over the same period, Victoria saw a steady increase in annual capex while values for the ACT have fluctuated, which may be partially attributable to costs associated with the introduction of smart meters.

27 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, p. 27. See

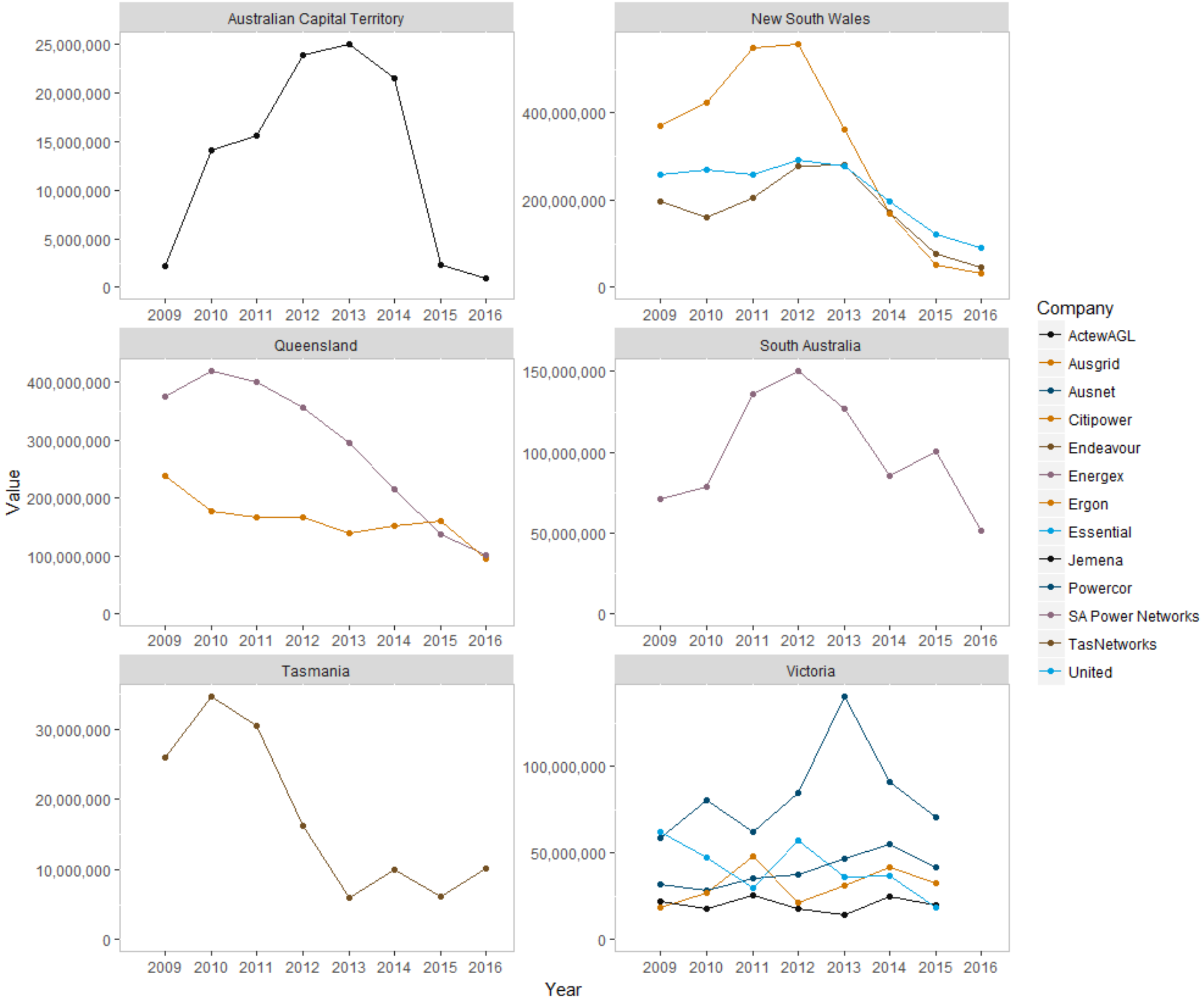
28 AER, *Electricity network service providers - Replacement model handbook*, p. 6. See https://www.aer.gov.au/system/files/AER%20model%20guide%20-%20replacement%20capex%20(repex)%20-%20draft%20expenditure%20forecast%20assessment%20guideline.pdf

Figure 3.2 Capital expenditure

Source: Data from Regulatory Information Notices (RINs) provided by DNSPs to the AER. AEMC charts and calculations.

Breaking capex down into its constituent parts reveals that for many DNSPs, augex expenditure tended to rise from 2009 to about 2012, and then to fall sharply - in most cases to less than its initial 2009 value. (Victorian DNSPs are an exception to this trend). It is worth noting that in spite of the decline, significant augex has continued to occur.

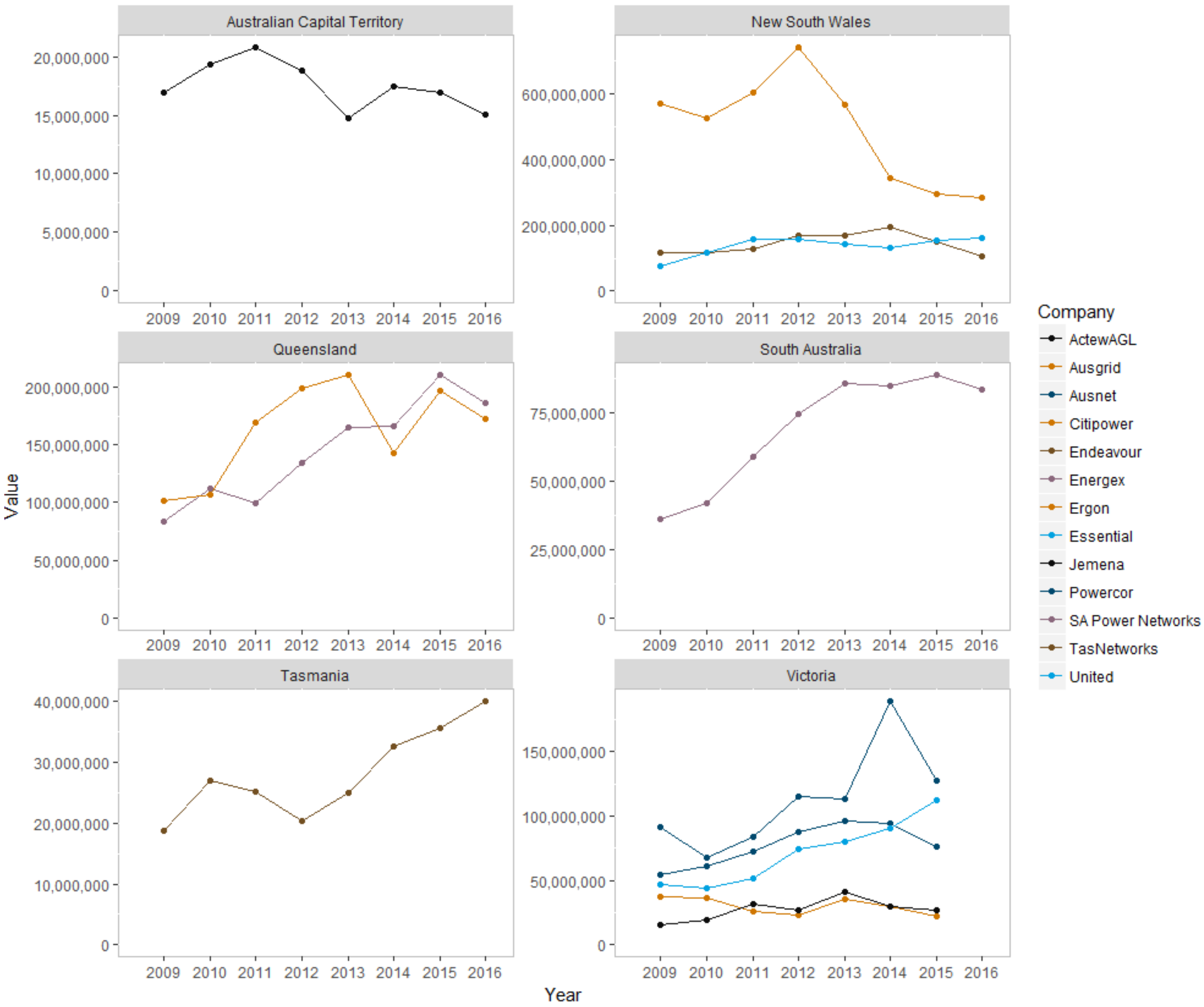
Figure 3.3 Augex



Source: Data from Regulatory Information Notices (RINs) provided by DNSPs to the AER. AEMC charts and calculations

While augex has declined, this trend has been partially offset by replacement expenditure, which has tended to increase year on year in most jurisdictions with the exception of the ACT and New South Wales.

Figure 3.4 Repex



Source: Data from Regulatory Information Notices (RINs) provided by DNSPs to the AER. AEMC charts and calculations

Overall, the broad trend is for capital expenditure to decrease, with a fall in augex partially offset by an increase in repex. However, investment in capex including augex is ongoing and substantial. As a result, the value of the Regulatory Asset Base (RAB) has increased in real terms for all DNSPs over the past ten years. This does not appear to reflect the trend of declining or flatlining maximum demand described in Chapter 3.

There are a number of potential explanations for the seeming mismatch between historical capital expenditure and trends in demand. These include the following:

- Capex has been undertaken to meet 'spikes' in maximum demand at particular locations which are not visible at an aggregated network level.
- Capex has been undertaken for reasons other than increased maximum demand, such as to meet reliability standards, bushfire safety or the rollout of smart meters in Victoria.
- Capex has been undertaken for technical reasons which may be related to the uptake of decentralised energy resources (for example, to enable two way flows of electricity).

- There are inadequate incentives under the existing regulatory framework for networks to respond to changes in demand in a timely fashion, or the incentives were inadequate prior to changes to the rules in 2012.
- While incentives under the existing framework are adequate, the 'rollover' between regulatory periods for DNSPs means that historical investment patterns reflect the historical and not the current regulatory environment.

These explanations are not mutually exclusive, and it is likely that some portion of some or all of the factors described above is at work. This will be discussed further in Chapter 4.

TNSPs

Changing patterns of demand, as well as the changing location of generation due to decentralised energy resources and other technologies such as wind farms, will also influence capital expenditure trends for TNSPs.

Capital expenditure trends for TNSPs have been broadly similar to DNSPs with both capex and augex tending to fall in recent years. However, unlike for DNSPs this decline has not been offset by an increase in repex, which has also tended to decline.

Figure 3.5 TNSP capex trends

Source: Data from Regulatory Information Notices (RINs) provided by DNSPs to the AER. AEMC charts and calculations.

3.3.2 Capacity utilisation and other partial performance indicators

The AER, along with other global regulators, monitors partial performance indicators (PPIs) for the purpose of benchmarking the performance of regulated businesses including energy networks.[29] PPIs are defined by the AER as simple indicators which relate one input to one output.[30] Among the PPIs used by the AER to assess DNSP performance are:

- Capacity utilisation[31] - a measure of the proportion of network capacity which is used in any given year.
- Cost per megawatt of maximum demand - calculated as total cost per DNSP[32] divided by maximum demand.
- Cost per kilometre of circuit line length - total cost divided by total length of circuit line.
- Cost per customer - total cost divided by the number of DNSP customers.

For the purposes of calculating PPIs total cost is defined as the sum of asset costs and operating expenditure. Asset costs are calculated as the DNSP's return on investment (the asset base or RAB multiplied by the regulated rate of return), less annual depreciation. This measure reflects the total cost of assets for which customers are billed on an annual basis.[33]

Increasing asset bases, in conjunction with flatlining or declining maximum demand, have reduced the level of capacity utilisation for DNSPs. As stated in the Approach Paper, the most critical risk to the network economic framework identified by the 2015 COAG 'stress test' of the market was the potential for an increased uptake of decentralised energy to lead to asset under-utilisation and/or stranding if network businesses do not take appropriate action to respond to these changes. Under the current economic regulatory framework, this could lead to material increases in the price of electricity for consumers who remain connected to the grid.

Over the past ten years capacity utilisation values have decreased for all DNSPs and in all jurisdictions besides the ACT. Capacity utilisation has gone from an average of 56 per cent per DNSP in 2006, to an average of 47 per cent in 2015.

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29 Other regulators using PPI analysis include Ofgem in the UK and the CER in Ireland. See ACCC, *Regulatory practices in other countries - benchmarking opex and capex in energy networks*, pp. 2, 4.

30 AER, *Distribution network service providers - Benchmarking report 2015*, p. 5.

31 Defined by the AER as the sum of non-coincident maximum demand at the zone substation level divided by summation of zone substation thermal capacity.

32 It is important to note that these costs are for DNSPs only, and do not include the retail or generation components of the cost of electricity.

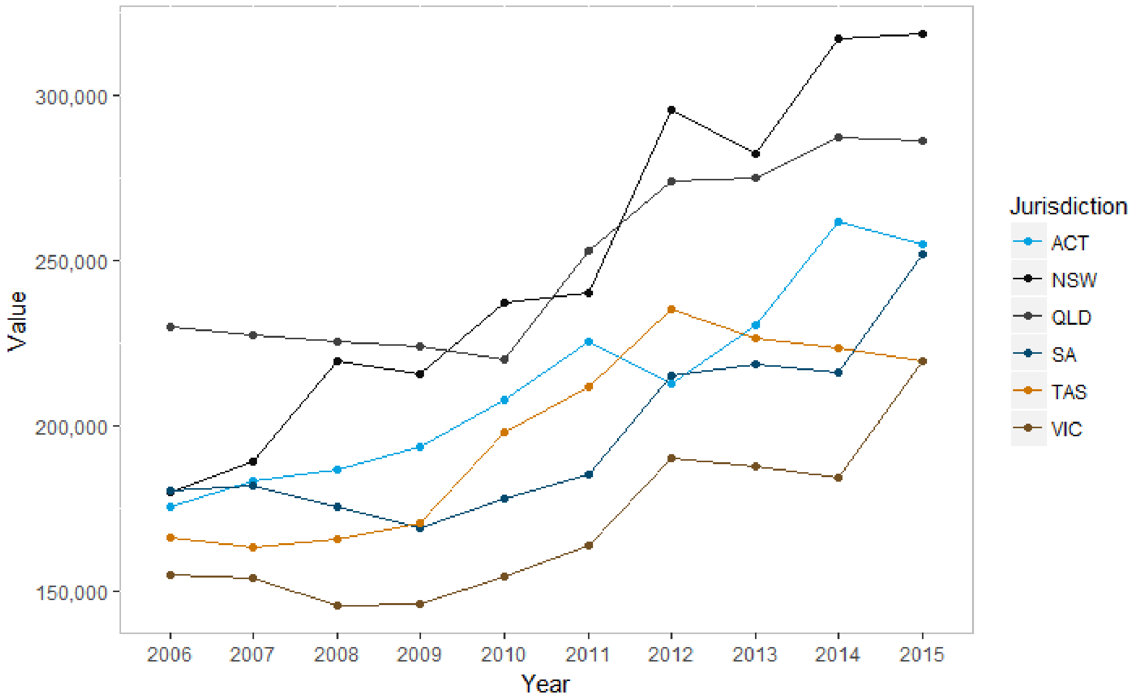
33 AER, *Annual Benchmarking Report: Electricity distribution network service providers*, November 2016, p. 20. See https://www.aer.gov.au/system/files/Final%20DNSP%20annual%20benchmarking%20report%202016%20-%20for%20release_0.pdf

Figure 3.6 Capacity utilisation

Source: AER, data from Regulatory Information Notices (RINs) provided by DNSPs. Charts by AEMC.

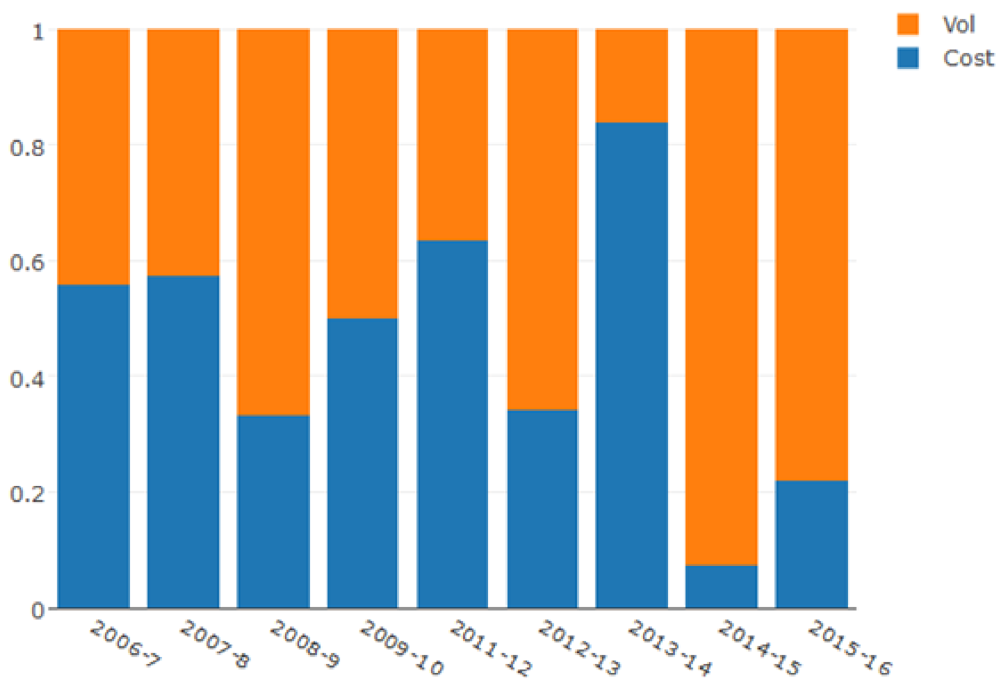
As a result, the cost per unit of maximum demand has substantially increased in real terms for all DNSPs in all jurisdictions. While the drivers of this increase vary from year to year and between DNSPs, both increasing costs and declining volumes have played a significant role.

Figure 3.7 **Cost per MW of maximum demand (2015$)**



Source: AER

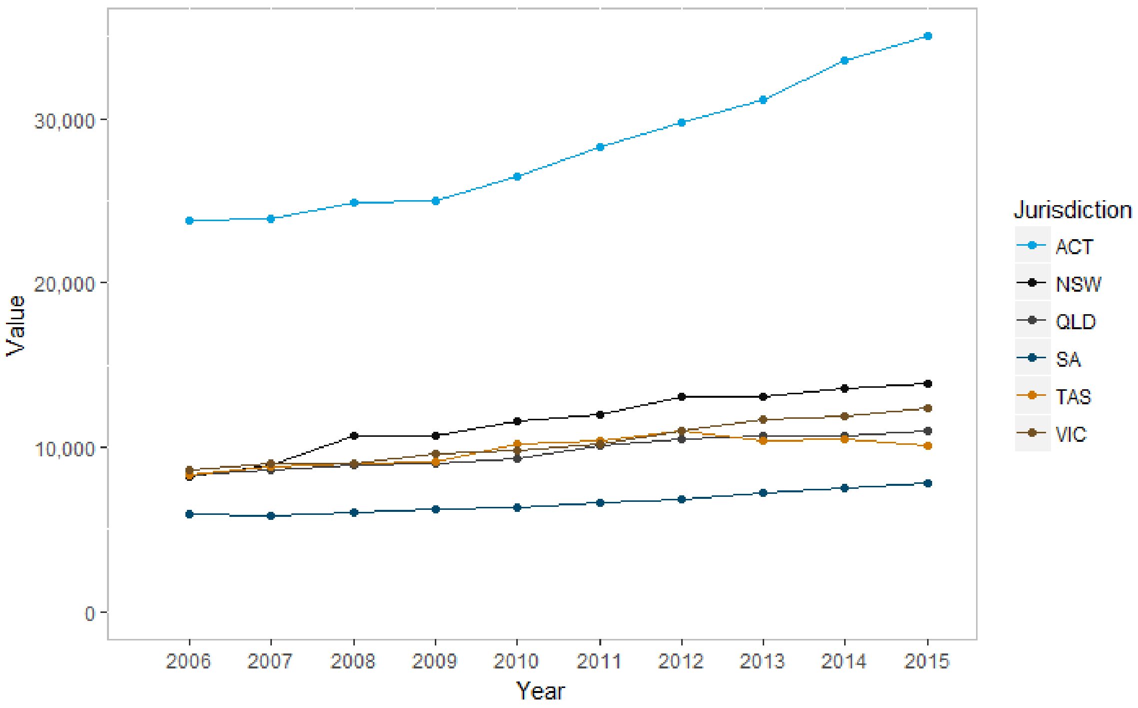
Figure 3.8 **Breakdown of components for year-on-year increase in cost per MW for sample DNSP**



Source: Data from AER, AEMC charts and calculations

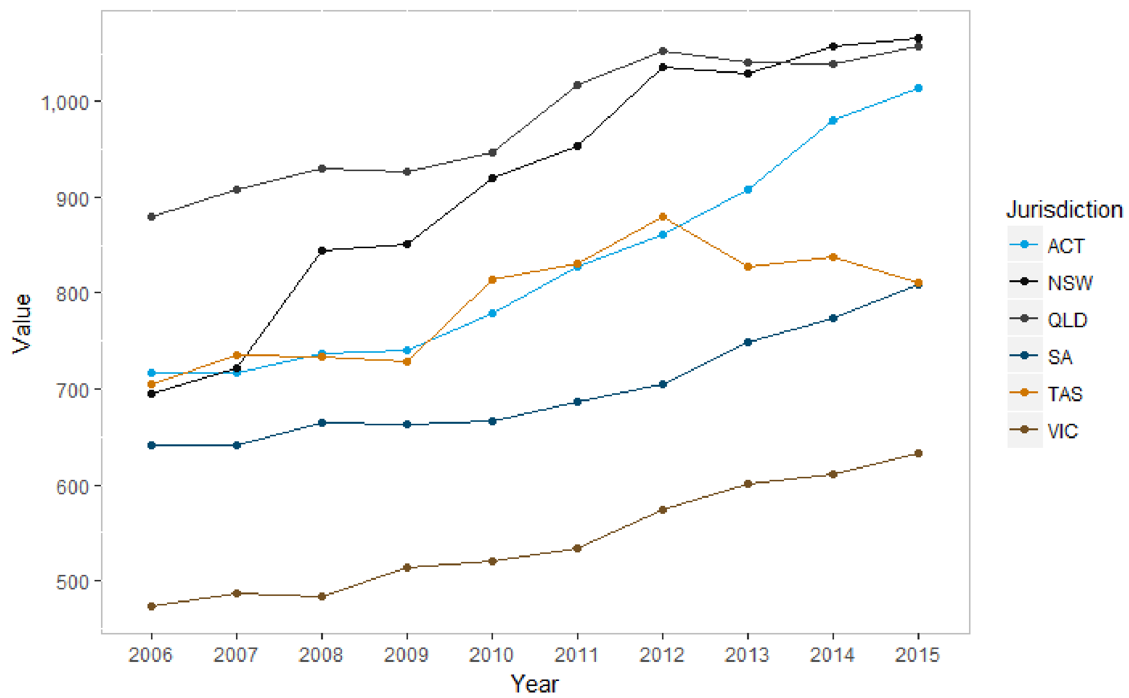
Other PPIs representing measures of unit costs for networks, including total cost per kilometre of circuit line length and total cost per customer, have increased in real terms in all jurisdictions.

Figure 3.9 Cost per km circuit line length (2015$)



Source: AER

Figure 3.10 Cost per customer (2015$)



Source: AER

3.3.3 Capital and operating expenditure

As the uptake of decentralised energy resources increases, and is projected to continue increasing in future, it is reasonable to expect the demand for traditional network services to decrease relative to non-network solutions. Capital expenditure would be expected to decline, as networks avoid expensive long-term investments which may soon be obsolete. Operating expenditure would be expected to increase, as new technologies replicate the services traditionally provided by networks. As a result of these trends, the ratio of capital to operating expenditure (capex/opex ratio) would be expected to decline.

The data suggests that the capex/opex ratio has fluctuated in recent years, with an overall decrease in all jurisdictions besides Victoria. At a high level, this may indicate that networks are increasingly turning to non-network solutions. However, capital expenditure continues to significantly exceed operating expenditure for most networks, suggesting that traditional network services continue to play the major role.

Figure 3.11 Capital/operating expenditure ratio

Source: Data from AER, AEMC charts and calculations

3.3.4 Use of non-network solutions

The existing regulatory framework provides some incentives for networks to use non-network solutions to meet demand, as discussed in Chapter 2.

Demand management is defined as the act of modifying the drivers of network usage, including reducing peak demand or changing the demand profile. Under the Demand Management Incentive Scheme (DMIS), the economic regulatory framework allows networks to access an 'innovation allowance' to cover their costs for pursuing non-network options.

Due to this scheme being a relatively recent development, only limited data regarding uptake is available. In absolute terms, participation has been low as reflected in the real value of Demand Management Incentive Allowance (DMIA) projects submitted for approval. In 2015 DNSPs submitted a total of $12 million in projects under the DMIA, equivalent to about 0.2 per cent of their total capital expenditure. In that same year, the Commission made a rule to strengthen the incentives for networks to invest in demand management, provided this investment is efficient. This was in response to concerns from stakeholders that previous scheme did not provide sufficient incentives for demand management.

Box 3.1 Ergon Energy case study[34]

Ergon Energy has implemented several targeted demand management initiatives in its network area. These aim to incentivise customers to reduce demand at specific locations and specific times. This, in turn, allows Ergon to manage peak demand on its network without additional investment. These demand management initiatives include:

1. **Demand Management Incentive Map**: The map is a communication tool to allow consumers and market participants to identify the value and location where customers may be able to earn payment in return for reducing their usage at peak times. The map is interactive and provides information down to the street or property level. The map identifies, through colour coding, whether a cash-back incentive is available currently or projected to be available in the next two years (based on projected demand growth);
2. **MacKay Northern Beaches and Townsville North West Incentive Program**: A cash-back program is currently available for business customers in the MacKay Northern Beaches and Townsville North West area to incentivise them to reduce peak demand on the network. Customers can earn $200 per KVA of demand reduction in the Mackay Northern Beaches area and $350 per KVA of demand reduction in the Townsville North West area. Examples of activities that may qualify a business consumer for the cash-back program include:
    - upgrading appliances and lighting to more energy-efficient models;
    - permanently removing or shifting electricity usage from the time of the network peak to off-peak periods; or
    - activity that results in an improvement to the power factor on the network.
3. **Network support payments**: Ergon has several network support agreements in place where demand management initiatives address an identified issue on the network. In the year 2014/2015, Ergon paid $2.58 million for a total of 34 MVA of network support.

34 AEMC, 'Final rule determination - National Electricity Amendment (Local Generation Network Credits) Rule 2016'.

3.3.5 Summary of network investment trends

Taken together, the indicators surveyed provide mixed evidence as to extent network investment trends have changed in response to changing trends in demand. Networks' capex trends reflect the evolution of the grid to an extent, through a general decline in augex and in the capex/opex ratio. However, significant ongoing augex alongside rising repex indicates that traditional network assets continue to play the major role. While the use of non-network solutions appears to be increasing, in absolute terms the uptake remains small. Unit costs continue to rise and capacity utilisation to fall, indicating that asset under-utilisation may be a material concern.

In future reports, the Commission will continue to monitor trends in network investment. Indicators will include capex, augex and repex, the capex-opex ratio, and uptake of the DMIS and of non-network solutions, as well as trends in PPIs including capacity utilisation.

3.4 Role of the regulatory framework

No regulator, or network business, can predict the future of demand for electricity with perfect accuracy. Inevitably, as structural and unforeseen shifts in energy usage occur, there will be forecasts which over or underestimate demand - with potentially significant consequences for investment. The key role of the regulatory framework is to **allocate the risk** of these unforeseen changes to those best placed to manage them. This will be discussed further in Chapter 4.

4 Applying the economic regulatory framework

The past decade saw the start of a consumer driven evolution of the energy market - this is likely to continue. Given the rapidly changing environment, it is important that the economic regulatory framework is able to adapt to an uncertain future.

As described in Chapter 2, the broad principle underlying the economic regulatory framework for network businesses is that of incentive regulation. No regulator can have the same detailed knowledge about an individual business or market participant as the individual themselves. Rather than specifying to stakeholders such as network businesses exactly how to spend their revenue, the framework seeks to put in place incentives that encourage desirable behaviour. These are rules or systems which motivate participants to behave in a way that is economically *efficient*, as well as providing them the flexibility to respond to changes in the market, thus maximising both their self-interest and the benefits across the broader community. In this way, incentive regulation supports the NEO in promoting long-term interests of consumers with respect to price, quality, safety, reliability, and security of supply of electricity and the national electricity system.

This chapter will describe the way the framework has evolved, as well as actions the Commission is currently undertaking to continue to promote the NEO in light of a changing environment. As 2017 is the first year of the annual monitoring task, this report will examine the operation of the economic regulatory framework to date as well as recent changes before describing how the framework has responded to increasing decentralised energy supply. It will also lay the groundwork for future editions of the report to assess how effective the framework has been in its goal of promoting the NEO.

4.1 The national electricity objective and the concept of efficiency

To understand how the framework is applied, it is useful to first discuss the national electricity objective (NEO) and the concept of efficiency. The NEO 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."

Central to the NEO is the concept of efficiency. For the purposes of this assessment, efficiency has three components:[35]

1. The first element of efficiency focuses on an individual task or process and is an evaluation of whether, for a given level of output, the value of resources (inputs) has been minimised.[36] If this is not the case there is an unnecessary economic cost

35 Australian Energy Market Commission, *Applying the energy objectives: a guide for stakeholders*, 1 December 2016.

36 This is known as productive efficiency.

in producing that level of output. In the context of electricity network regulation, this would mean providing the regulated services, including the obligation to connect and meet reliability standards, for as little expenditure as possible.

2. The second element of efficiency is concerned with allocating resources to produce the right mix of things.[37] The right quantity of the right kinds of output are being produced and consumed, and stakeholders are not missing out on opportunities to use the same resources in more highly valued ways. In the context of electricity network regulation, this could include an appropriate combination of network and non-network solutions.

3. The first two elements of efficiency are based on an assessment of a market at a particular point in time. The last element considers the prospects for having the right mix of resources, to produce the maximum amount for the minimum cost, over time.[38] In the context of electricity network regulation, this would mean that network services continue to be produced at lowest cost and that resources to be well-allocated even as technologies and other circumstances continue to evolve.

Another key principle applied by the Commission is that risks should be allocated to those best placed to manage them. The party which holds the risk, in that it bears the consequences if that risk were to eventuate, has the incentive to manage the risk because it stands to gain or lose from doing so. Ideally, this party will also have:

- more information than other parties regarding the nature and impact of the risk;
- the ability to take actions to avoid or reduce the impact of the associated loss; and
- the ability to improve risk management over time through experience.

4.2 How the Commission applies the principles of the NEO to the economic regulatory framework

Table 4.1 below describes how the principles of economic efficiency discussed above apply to the economic regulatory framework.

Table 4.1 Applying efficiency components to networks

Efficiency criteria	Application to networks
• Does the economic regulatory framework provide the right incentives to network businesses to produce services at lowest cost?	• Network services, including obligation to connect and meeting legislated reliability standards, are provided at the lowest possible cost given available technologies and resources at a given point in time.
• Is the right mix of network and non-network services being produced and consumed?	• NSPs and other stakeholders provided with incentives to use non-network solutions where this is appropriate. • No bias in allocating spending between capex and opex.

37 This is known as allocative efficiency.

38 This is known as dynamic efficiency.

Efficiency criteria	Application to networks
• Is the economic regulatory framework flexible enough such that these outcomes can continue to be achieved over time?	• Framework with no bias towards or against any particular technology. • Framework is flexible enough to accommodate new market developments, including new participants and business or operating models • Does not create inefficient barriers preventing entry by new technologies or business models. • Framework encourages efficient reductions in cost and/or improvements in reliability and other measures of network quality over time.

Network businesses cannot be simply evaluated as 'efficient' or 'inefficient'. To some degree, 'efficiency' is a theoretical concept which cannot be perfectly observed. There are considerable uncertainties in any market, and the market in which network businesses operate is no different. For example, it is difficult to determine whether any particular distribution business is producing services at the lowest possible cost given the many variables which go into determining that cost, and which are far from uniform between businesses. Some of these variables include geography, consumer numbers and preferences, levels of demand, rate of asset degradation and so on.

The uncertainty is greater for the forward-looking component of efficiency since it is impossible to perfectly predict technological change and progress. Even under an ideal regulatory framework, optimal outcomes may still not occur. For instance, a market participant acting on the best available information at a point in time may over or under invest in a particular new technology. This will have ramifications for the cost at which they produce output in future. For these reasons, it is not possible for the Commission (or any other body) to describe exactly what should happen in a perfectly functioning market.

Nevertheless, over time it is possible to evaluate to some degree whether the economic regulatory framework is achieving its intended outcomes. The purpose of regulation is to generate substantive, material benefits by promoting the NEO, which will over time become visible to regulatory bodies and other stakeholders.

The Commission considers it is not appropriate to issue an assessment of the framework in this first edition of the annual Review. Rather, the purpose of this report is to present initial indicative data and criteria for assessing the efficacy of the regulatory framework, to set out a foundation for further assessment. In future editions, the Commission will aim to assess whether the framework is currently succeeding at its goals as well as whether it is likely to remain fit-for-purpose in the future.

4.3 Does the economic regulatory framework provide the right incentives to network businesses to produce services at lowest cost?

4.3.1 Historical observations

The simplest indicator of whether output is being produced at lowest cost is the actual cost of producing network services. If the cost of production (per unit of output, including the quantity of energy delivered, the number of customers and the level of reliability) is static or declining over time, this would tend to support the hypothesis that the regulatory framework provides adequate incentives for this goal to be achieved.

As illustrated in Chapter 3, this is not the case. By multiple measures, the cost of producing distribution network services had been increasing in all jurisdictions over the past ten years. Two significant contributors to the increase in costs are growth in DNSPs' regulatory asset base, and declining utilisation rates.

Factors driving historical increase in costs

Increasing costs do not necessarily reflect any regulatory failure, or even sub-optimal decision making by DNSPs given the information available. One factor that has historically driven rising asset costs in two jurisdictions is an increase in reliability standards. In 2004, in response to severe blackouts the previous year, the Somerville Report[39] in Queensland recommended significant increases in (enforcement of) reliability standards for DNSPs. In 2005, New South Wales moved to strict 'n-1' and ‘n-2’ reliability standards which led to NSW DNSPs undertaking substantial capital investment.[40]

Similarly, there is a case to be made that the trend of flatlining or falling demand (including maximum demand) was historically unprecedented[41] and could not have been reasonably foreseen by DNSPs.

However, while these factors drive costs to some degree, they may not be adequate as a complete explanation for the growth in cost.

Reliability standards

First, while historical changes in reliability standards have certainly played a role in increasing RAB values, large cost increases driven by RAB growth are occurring in all DNSPs across all jurisdictions, not just New South Wales and Queensland (except South Australia).

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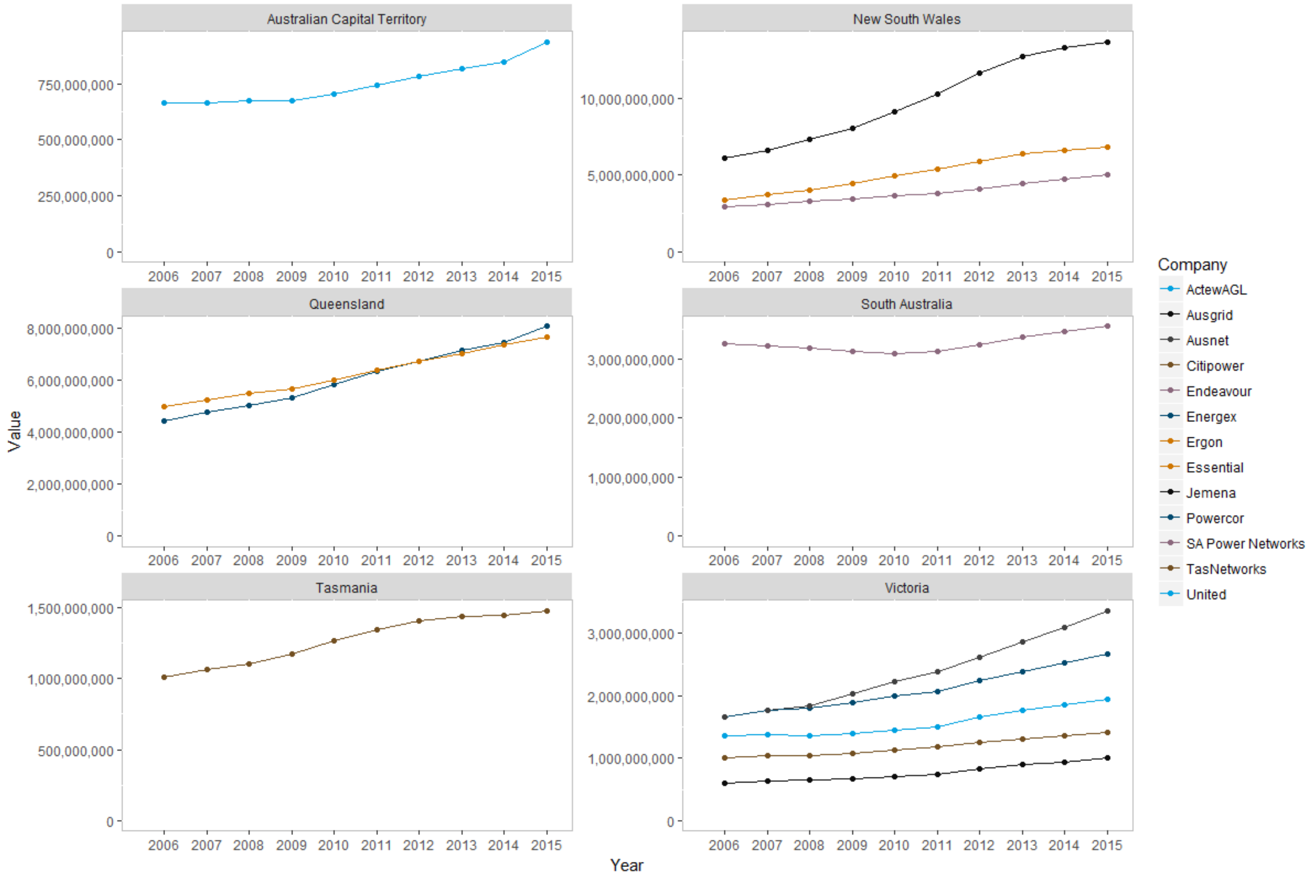
39 See explanatory note to the Hon Anthony Roberts MP, Minister for Resources and Energy, 'Reliability and Performance Licence Conditions for Electricity Distributors - commencement date 1 July 2014', p. 2.

40 Independent Review Panel on Network Costs, ‘Electricity Network Costs Review Final Report’, 2014, p. 42.

41 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

Figure 4.1 RAB growth by DNSP (2015$)



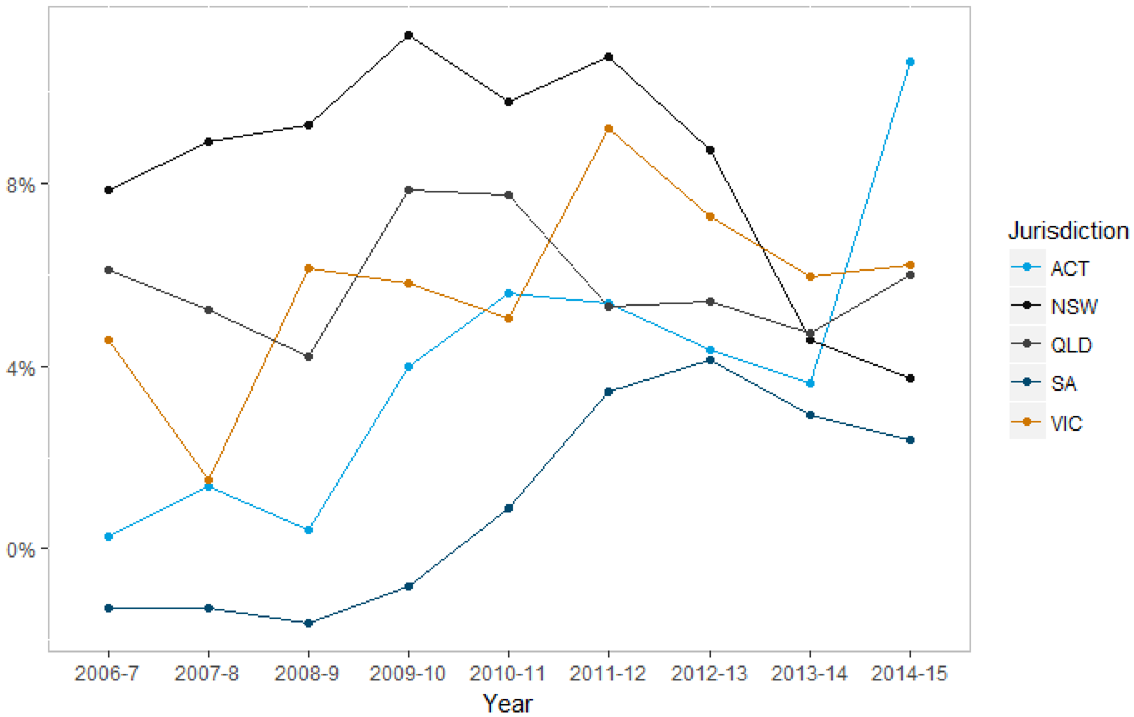
Source: AER

Even in the affected jurisdictions, the impact of policy changes which occurred in 2004-5 would be expected to moderate over time as the necessary augmentations and other capital investments are completed. In 2012, the Commission's *Review of Distribution Reliability Outcomes and Standards* noted that the majority of the capital expenditure to meet the new standards in NSW would be likely completed within the (then) current regulatory period, particularly given that DNSPs were expected to be as compliant as reasonably practicable by 1 July 2014.[42]

While there is only a limited amount of information since that time available, it appears RAB values are continuing to grow at a substantial rate. Figure 4.2 below tracks the year on year average percentage growth in RAB by jurisdiction. While growth in New South Wales has moderated somewhat (albeit from a high base), growth in Queensland shows no obvious downward trend. Other jurisdictions such as the Australian Capital Territory and Victoria also continue to show significant growth.

42 http://www.Commission.gov.au/getattachment/a5bbc0be-e7e3-4fcd-b856-feaf4088d38a/NSW-workstream-final-report.aspx - see page 30

Figure 4.2 Year on year percentage change in RAB by jurisdiction



Source: Data from AER, AEMC calculations and chart.

The Commission has performed some initial quantitative work which may suggest that the historical growth in RAB values has not been strongly or obviously correlated with real improvements in reliability. Where reliability has increased, the magnitude of the improvement often appears to be marginal and appear small relative to the size of the increase in cost, a finding shared by other stakeholders.[43] However, this work remains at the preliminary stage. The Commission will explore these issues further in future editions of this report.

Declining demand and risk allocation

There are inherent risks associated with forecasting efficient levels of capital expenditure. DNSPs invest in capex based on their projections of future demand on the network, which in turn are partially based on demand forecasts prepared by AEMO. Capex allowances for each regulatory control period are also approved by the AER based on its own estimate of what 'efficient' capex would be.

As the future is intrinsically uncertain, these forecasts will always be inaccurate to a greater or lesser degree. If DNSPs' forecasts significantly underestimate future levels of demand, they may spend too little on capex. As a result, they may fail to meet legislated reliability standards, resulting (for example) in unplanned outages. This will cause them to incur penalties under the STPIS. The risks associated with under-investment are thus shared between DNSPs and consumers.

On the other hand, if DNSPs invest in capex based on forecasts of demand which turn out to be too high, this will result in underutilisation and increasing costs. Over time these costs will be recouped from consumers. The risks associated with over-investment

43 Infrastructure NSW, 'The State Infrastructure Strategy 2012-2032', p. 152

based on significantly incorrect demand forecasts are thus borne by consumers but not DNSPs.

A preliminary analysis of this risk allocation, based on the Commission's application of NEO,[44] is presented below:

- Where over-forecasting of demand and subsequent over-investment in the network occurs, DNSPs may bear partial responsibility. Compared to other parties, they have access to significant information and experience regarding trends in demand and utilisation for their own assets. They are also responsible for translating these forecasts into specific capex decisions.
- DNSPs therefore have some ability to take actions to avoid or reduce the impact of overinvestment - for example, by improving the accuracy of their forecast capex requirements.
- Once assets have been rolled into the RAB, the cost of financing those assets is passed on to consumers. This is the case regardless of whether subsequent information emerges to indicate that inefficient capex has occurred.
- DNSPs therefore have significant ability to manage the risk of over-investment but limited incentives to actually do so.

Over time, any gap between forecast and actual efficient investment levels caused by an unexpected shift in demand would be expected to narrow, as DNSPs update their forecasts in response to this new information. Since 2009 AEMO has substantially updated its demand forecasting methodology, establishing a work program to improve the accuracy of its long term forecasts in order to support improved system planning (see Figure 3.1).[45] As a result, the gap between AEMO’s forecast and actual electricity demand has substantially closed in recent years.

It is important to note that it is probably not efficient for DNSPs to have to bear the *entire* risk of any overspend on capex. Responsibility for any overspend is likely to be shared between multiple parties. For example, as stated above the role of forecasting demand is shared between DNSPs and AEMO. The role of estimating 'efficient' capex based on these demand forecasts is shared between DNSPs and the AER, and the role of setting rules which allow for that efficient estimation of capex belongs to the Commission. Furthermore, as described in Chapter 2, DNSPs are legally constrained from undertaking some actions which might reduce costs such as disconnecting certain customers.

However, under the current framework, DNSPs bear *some* responsibility for any over-investment which may (theoretically) take place, and have *some* ability to reduce or mitigate the risk of such decisions, they assume *none* of the risk of any over-investment which might take place, subsequent to those assets being added to the RAB.

44 AEMC, 'Applying the energy market objectives - a guide for stakeholders', p. 14.

45 ‘Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future’, p. 135

In future editions of this Review, the Commission will undertake further analysis to determine whether this allocation of risk remains appropriate in the future with increasingly uncertain demand.

Next steps

It should be emphasised that no single piece of quantitative evidence exists, or even *can* exist, to definitively prove whether expenditure has been efficient. DNSPs run complex businesses. Costs are determined by multiple factors, including (but not limited to): the cost of financing, other production costs including labour, terrain, the weather, location of consumers, new greenfield development, and the age and condition of assets. There will always be unexplained variation in costs between DNSPs and over time. This in itself is not proof of any inefficiency.

Nevertheless, a broad range of indicators gathered by different institutions, and using different methodologies and sources, suggest that output is not currently being produced for lowest cost and that costs are increasing. This is not fully explained by factors such as an increase in reliability standards or unforeseeable changes in demand.

For example, the AER's 2016 annual benchmarking report[46] for DNSPs found that productivity across the industry has been declining since 2007. A 2013 Productivity Commission report[47] has also found that not all of the increased investment in capacity appears to be an efficient response to changes in peak demand.

In future editions of this Review, the Commission will investigate further to identify the drivers of growth in costs.

4.3.2 Recent rule changes addressing the issue of incentives

It is important to distinguish between the regulatory framework *historically* and at the present time. As large capital investments tend to be planned some years in advance, there may be a lag between corrections to the framework (or updates to DNSPs' or AEMO's demand forecasts) and a reduction in costs. Ongoing high asset costs may therefore be the result of previous gaps in the regulatory framework which have since been amended.

There have been a number of recent rule changes designed to incentivise DNSPs to invest and operate more efficiently. As described in Chapter 2, the 2012 *Economic Regulation of Network Service Providers* rule change gave the AER greater flexibility over how network revenues and prices are determined. The rule change also required the AER to publish annual reports on the relative efficiencies of electricity network businesses. This provides public information on the relative performance of the DNSPs.

Similarly the CESS and EBSS guidelines developed in 2013 (and described in Chapter 2) seek to incentivise continuous efficiency improvements throughout the regulatory period as well as sharing efficiency gains and losses between the DNSPs and

46 See Chapter 2 of the AER's *Annual Benchmarking Report: Electricity distribution network service providers*, November 2016.

47 See Chapter 6 of Productivity Commission 2013, *Electricity Network Regulatory Frameworks*, Report No. 62, Canberra.

consumers. The combined operation of the EBSS and CESS balances the incentive for DNSPs to choose between capital and operating expenditure.

Under the Capital Expenditure Incentive Guideline also published in 2013, the AER has limited powers to conduct an ex post review of capex, and to exclude from the RAB inefficient or imprudent capex overspends or related party margins, or opex that has been capitalised due to a change in a NSP's capitalisation policy.[48]

In 2015, the Commission made a rule that aim to balance incentives for distribution businesses to undertake demand management projects as alternatives to implementing network options. The *Demand Management Incentive Scheme* rule responds to concerns that the current regulatory framework creates a bias towards expenditure on network investment over non-network options. The rule is designed to complement existing arrangement that encourage network businesses to consider non-network options where it is efficient, and regardless of whether it is provided by the network businesses or third parties. The rule also provide for a separate allowance (demand management innovation allowance)to fund research and development in demand management projects that have the potential to reduce long term network costs.

Table 4.2 below provides a summary of recent rule changes alongside the date of implementation and current status in the market.

Table 4.2 Recent rule changes

Rule Change	Objective	Date of implementation/timeline for commencement	Current Status
Economic regulation of network service providers	This rule aimed to better equip the AER to develop methods and processes to achieve efficient outcomes in setting revenues and prices for consumers in a number of areas, including greater use of benchmarking and limited ex post capex reviews.	Rule made 29 Nov 2012. Guidelines developed Nov/Dec 2013	Implemented through development of a range of guidelines by the AER including rate of return guideline, shared asset guideline and capital expenditure incentives, and current revenue determinations
Capital expenditure sharing scheme (CESS)	The CESS encourages network businesses to make efficient decisions, providing a network business with the same reward for an efficiency saving and same penalty for an	Guidelines developed 29 Nov 2013	Guideline is currently being implemented and applied by the AER through current revenue determinations.

48 AER, 'Better Regulation Explanatory Statement: Capital Expenditure Incentive Guideline for Electricity Network Service Providers', November 2013.

Rule Change	Objective	Date of implementation/timeline for commencement	Current Status
	efficiency loss regardless of which year they make the saving or loss in.		
Efficiency benefit sharing scheme (EBSS)	The EBSS provides a continuous incentive for businesses to achieve efficiency gains in such a way that they will not benefit from inflating operating expenditure in any one year.	Guidelines updated 29 Nov 2013	Guideline is currently being implemented and applied by the AER through current revenue determinations.
Demand management incentive scheme (DMIS)	The objective of the DMIS is to provide distribution businesses with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management. The scheme will reward distribution businesses for implementing relevant non-network options that deliver net cost savings to retail customers, where it is efficient to do so.	Rule made in August 2015	The AER is currently consulting on the development of the DMIS. The AER is expected to publish the final scheme in October/November 2017

4.4 Is an appropriate mix of services being produced?

4.4.1 Historical observations

Services traditionally provided by networks can in some cases be provided at lower cost through non-network solutions including demand response, embedded generation and load shifting. Non-network solutions have the potential to reduce network costs (and therefore save money for consumers) by deferring or avoiding the need for network augmentation. A successful regulatory framework should allow for and incentivise their use under these circumstances.

It is not the role of the economic regulatory framework to determine what the ideal or efficient level of uptake of non-network solutions should be. It is likely that the optimal level will be greater than zero, as there are likely to be some instances where non-network solutions are cheaper than the 'traditional' alternative. It should also likely be increasing over time, as technology improves and more non-network solutions become available. However, how *much* greater than zero and how *fast* this increase should occur are questions without an obvious answer. An added complicating factor is that due to the low levels of capacity utilisation described in Chapter 3 (caused in part by flat or declining demand), the opportunity to implement non-network solutions in the near future may be limited.

The current regulatory framework clearly allows for the use of non-network solutions by DNSPs and other stakeholders. The Commission’s research and discussions with stakeholders have revealed a number of case studies, some of which are described in greater detail in Appendix A.2. These include:

- Energex's 'PeakSmart' demand management program
- South Australia Power Networks' and AusNet's (separate) trials of large scale battery storage
- Reposit’s energy management software
- The deX platform for the trading of decentralised energy resources

The framework provides a number of incentives and obligations for DNSPs and other stakeholders to use non-network solutions where it is efficient to do so.

The **RIT-D** and **RIT-T** are regulatory investment tests for distribution and transmission networks respectively. A RIT-D requires DNSPs to assess the costs and, where appropriate, the benefits of each credible investment option to address a specific network problem to identify the option which maximises net market benefits (or minimises costs where the investment is required to meet reliability standards). Similarly, a RIT-T requires TNSPs to apply a cost-benefit assessment to augmentation investments in the transmission networks. The requirement to undertake a RIT-D or RIT-T only applies to investments over certain cost thresholds. Any party may apply to the AER to dispute the conclusions of a RIT-D or RIT-T. While conclusions of the assessment are not binding on DNSPs or TNSPs, the AER has regard to the outcomes of RITs when determining efficient capex and opex in its determinations.

As described in Chapter 2, the Demand Management Incentive Scheme (DMIS) provides DNSPs with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management. The scheme will reward DNSPs for implementing relevant non-network options that deliver net cost savings to retail customers. The Demand Management Innovation Allowance (DMIA) provides DNSPs with funding for research and development in demand management projects that have the potential to reduce long term network costs. The allowance will be used to fund innovative projects that have the potential to deliver ongoing reductions in demand or peak demand.

4.4.2 Ongoing discussions regarding capital expenditure bias

As discussed in section 2, recent and ongoing changes[49] to the economic regulatory framework sought to strengthen incentives to network businesses to seek alternatives to traditional network solutions. However, some stakeholders have raised concerns there is an inherent bias for network businesses to prefer capital expenditure over operating expenditure. A report commissioned by the COAG Energy Council in July 2015 articulated the view that the guaranteed rate of return on the RAB could create an overwhelming incentive for network businesses to continue focussing on building new network over and above other more efficient technology based solutions,[50] a concern reiterated in stakeholder submissions. A recent rule change request, *Contestability of energy services – network support and demand response,* submitted by the Australian Energy Council raised a very similar issue.

While the Commission believes incentive regulation remains the preferred framework to promote the long term interests of consumers, it is nonetheless timely to examine incentives provided by the current regulatory framework.

Box 4.1 Network businesses' financial incentives in delivering economically regulated services

Giving the ongoing concerns about biased incentives towards network businesses preference on capital expenditure, the Commission will include in its 2017-18 work program a review of the financial incentives that network businesses face in delivering economically regulated services under the existing regulatory framework. This analysis will be particularly focussed on the financial incentives NSPs face to deliver their regulated services using distributed energy resources based solutions relative to traditional network solutions.

The analysis would include assessments of the incentives NSPs face to undertake:

- Capital or operating expenditure service delivery methods;
- Long or short asset life service delivery methods;
- Network or non-network service delivery methods; and
- In-house or third party service delivery methods.

The Commission will also examine frameworks that overseas regulators have adopted as a result of findings that their previous regulatory frameworks did not provide balanced incentives for service delivery methods. This will include the total expenditure based frameworks adopted in the United Kingdom for electricity, gas and water regulation. Under these frameworks the distinction between capital and operating expenditure (both in assessment and recovery method) is removed.

49 For example, the Commission's 2012 rule on *Economic regulation of network service providers* and the AER's 2016 rule change request to extend the regulatory investment tests to replacement capital expenditure.

50 COAG Energy Council, 'Electricity network economic regulation scenario analysis: policy advice', June 2015.

4.4.3 Network pricing reform

An area of reform that has significant potential to improve incentives to allocate resources efficiently between network and non-network solutions and reduce future network capex is network pricing reform. Currently, the cost of augmenting the network to deal with a local constraint is shared between all customers of the DNSP. Prices for network services therefore do not necessarily reflect the actual cost of producing those services, but an average across the network area.

A lack of cost-reflective network pricing inhibits the efficient allocation of resources in two ways, both of which relate to people not having access to the information they need to make informed and efficient usage and investment decisions. The first is by distorting the incentives for businesses to develop services which help energy users adjust their consumption in response to its true cost.

Even if it is cheaper in real terms for some users (for example) to shift devices that have significant energy usage (such as air conditioners and pool pumps) from peak to off-peak hours, businesses have limited reason to help consumers do so, as they do not pay the full costs of peak hour use, including congestion and potential need for augmentation of the network. For example, businesses which might have developed around co-ordinating demand management programs have less incentive to operate and offer services to help customers save money. On the flip side, consumers and businesses may forgo opportunities to consume more energy at times when the real cost of doing so is low.

The second way in which a lack of cost-reflective pricing inhibits efficiency is by reducing the information available to stakeholders. Cost-reflective pricing can act as a signal for investment, including when and where distributed generation or demand response needs to be deployed to help reduce future network capex.

In 2014, the Commission's *Distribution network pricing arrangements* rule change established a new pricing objective requiring DNSPs to set network prices which reflect the efficient costs of providing network services. This will allow consumers and their agents to compare the value they place on using the network against the costs caused by their use of it, and make decisions accordingly. Network prices based on the new pricing objective are being phased in from 2017.

Box 4.2 Continual implementation of network pricing reform

In addition to establishing new pricing objectives, the *Distribution network pricing arrangements* rule change also introduced new processes and timeframes for setting network prices and requires distribution network businesses to consult with consumers and retailers to develop a tariff structure statement (TSS) that outlines the price structures that they will apply for the regulatory period.

The first TSS period, which is from 2017 to 2019, has seen network businesses introducing demand based or time-of-use tariffs that better reflect the cost of the networks, albeit generally on an ‘opt-in’ basis.

It is important that network businesses build upon their current work in the next TSS period in 2019. The implementation of reflective pricing will create the essential foundation for future reforms, including more advanced pricing options such as dynamic and locational pricing in the future.

The Commission also considers cost reflective pricing as a prerequisite to a well-functioning and competitive energy services market. As discussed above, cost reflective pricing not only provides a signal to consumer of electricity, but also facilitates development of services that assist consumers in optimising their energy usage and sends an investment signal to distributed energy resource providers.

The Commission believes that a combination of these outcomes will lead to a more efficient use of the energy system, and ultimately, lead to a more sustainable and lower cost distribution network.

4.5 Will efficiency continue to be achieved over time?

Despite educated guesses, no-one can know in advance exactly which technologies will succeed and which will fail or how costs will change - particularly since regulatory decisions themselves can influence how technologies develop. Applying the regulatory framework to provide the right incentives to achieve efficiency over time ('dynamic efficiency') is therefore difficult. There is more inherent uncertainty associated with this facet than with the aspects of efficiency evaluated previously in this chapter. The role of the framework is not to determine exactly what electricity networks will look like in future, but to create the right incentives so that the many different businesses and stakeholders who participate in networks can iterate towards the right solution.

A regulatory framework which promotes dynamic efficiency will have the following characteristics:

- **No inefficient barriers to entry**. For example, a particular technology or business model should not be barred from participating in the market just because it is has not participated in the market before, even though it provides equivalent services to other participants.

- The incentive framework should be **technology neutral**. Businesses and stakeholders should face rewards and costs based on the services they provide, not the technologies they use to provide these services.
- The framework should allow for **intervention to correct market failures** in the isolated cases where this is needed.

4.5.1 Historical observations

The simplest test of whether there the framework creates barriers to entry is to assess whether new technologies and business models are, indeed, entering the market. The research and consultation with stakeholders conducted as part of this report indicate they are. Appendix A.2 describes how devices such as batteries are seeing rapid growth in uptake. It also provides a number of examples of innovation including devices to optimise the timing of household energy consumption and battery discharge, cloud-based schemes to aggregate batteries and/or demand response, and digital platforms for peer-to-peer trading. These technologies and new business models have all been developed under the current incentive framework.

As a result, aspects of the regulatory framework may need to be updated from time to time to make sure that it remains fit for purpose in a changing environment. The Commission is conducting a number of reviews and rule changes in this vein, including the below:

- The ***Distribution Market Model*** project is exploring how the operation and regulation of networks may need to change to accommodate an increased uptake of distributed energy resources. The final report will be published on 15 August 2017.
- The ***Contestability of energy services*** rule change seeks (among other goals) to promote contestable provision of a range of energy services. This is to ensure that as technologies change, providers of services that are no longer natural monopolies are not able to continue exercising monopoly powers in the market.
- Western Power has submitted the ***Alternatives to grid-supplied network services*** rule change request. The proposal seeks to change the definition of "distribution service" in the National Electricity Rules so that it may include (among other things) off-grid supply provided in certain circumstances.

Box 4.3 Distribution market model

Historically, the development of distribution networks, and the regulatory arrangements that underpin them, have been focused on distribution network businesses providing sufficient network capacity to meet increasing consumer demand while maintaining the safety, reliability and security of electricity supply.

However, in light of the increasing uptake of distributed energy resources and the range of services they are capable of providing, distribution system operations and associated regulatory arrangements are likely to require greater consideration of two other issues: the value of optimising investment in and operation of distributed energy resources, and the value of coordinating the operation of distributed energy resources with the wholesale market.

The Commission has therefore initiated an internal research project to explore the key characteristics of a potential evolution to a future where investment in and operation of distribution energy resources is optimised to the greatest extent possible and where there is greater coordination of the operation of distributed energy resources with other markets.

The Commission considers that promoting the development of a competitive distribution market for the provision of services enabled by distributed energy resources means that markets, in response to consumer decision-making, determine the most efficient outcome.

In the Commission's view, such a market can develop where there is a level playing field for the provision of 'optimisation' services. A level playing field means that any party taking on the optimising function is independent and exposed to financial incentives. This means that regulated NSPs should not take on an optimising function because they are not independent of the provision of certain services, i.e. network services.

The draft report for the *Distribution Market Model* project was published on 6 June 2017. Stakeholders submission closed on 4 July and the Commission is expected to publish the final report in August 2017.

4.5.2 AER discretion

In addition to the rules, schemes and guidelines, it is also important to note that the AER has significant discretion within the current economic regulatory framework to adapt how it regulates in light of any changes in the market. This discretion includes determining the following aspects of a network business's revenue determination:

- control mechanism;
- service classification;
- cost allocation; and
- shared assets.

The Commission will be assessing the implications of the recent Federal Court decision in relation to the limited merits review process with regards to the appropriate level of flexibility in the rules.

Appendix 1 Changing trends in demand

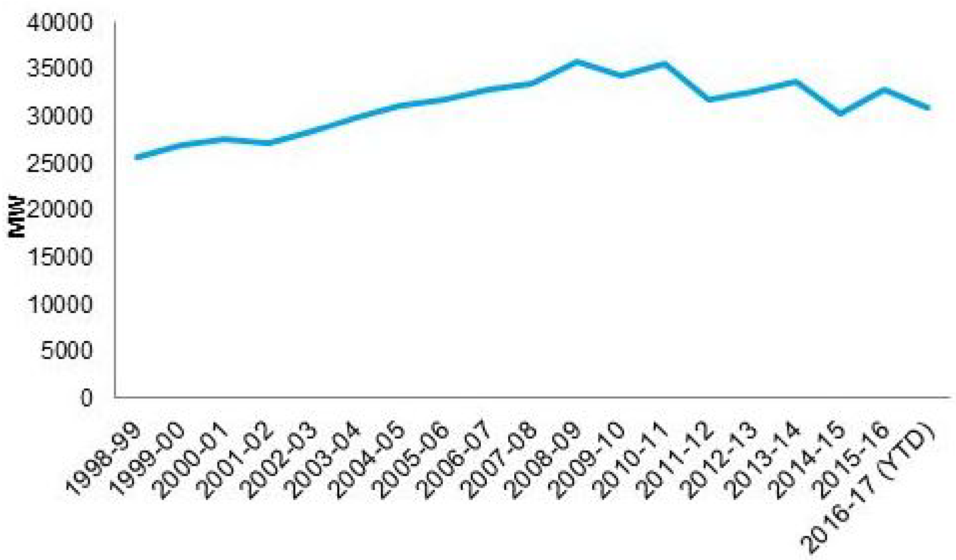
This section will examine trends in electricity demand and consumption. As per AEMO's definition, consumption is used here to refer to electricity used over a period of time (MWh), while demand is used to describe electricity used at a particular time (MW).[51]

Maximum demand

While total demand is declining, investment in the network is largely driven by the requirement to accommodate maximum demand. Operational maximum demand is defined as the highest level of instantaneous operational demand[52] during summer and winter each year, averaged over a 30-minute period, and does not include demand met by rooftop solar PV.

Figure A.1.1 displays actual maximum demand trends since 1998-9. As with total demand, the highest actual maximum demand occurred in 2008-09, followed by an unexpected decline and divergence from forecast.

Figure A.1.1 Maximum demand



Source: AER, AEMO

51 See AEMO's 'Operational Consumption 2016 Update', viewed June 2017 at https://www.aemo.com.au/media/Files/Other/planning%202016/Operational%20Consumption%20definition%20%202016%20update.pdf

52 AEMO uses the term "operational" to describe electricity used in the NEM. Operational demand refers to the electricity used by residential, commercial and large industrial consumers, as supplied by scheduled, semischeduled and significant non-scheduled generating units. It does not include electricity used by scheduled loads or met by rooftop solar PV. See AEMO's *Operational Consumption Definition 2016 Update*, viewed March 2016 at https://www.aemo.com.au/media/Files/Other/planning%202016/Operational%20Consumption%20definition%20%202016%20update.pdf

Maximum operational demand varies between jurisdictions; this is largely due to the different characteristics of each jurisdiction including climate, population and customer location. In recent years, maximum demand has been falling across the NEM. Queensland is the only jurisdiction where demand has increased in recent years, partly due to new LNG export facilities.

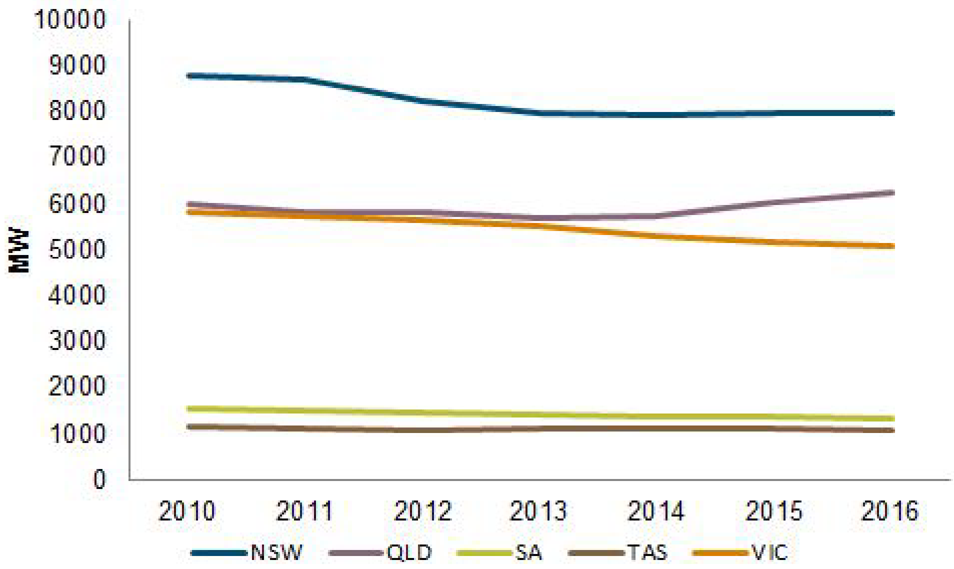
Average demand

A useful comparison can be drawn from examining trends in both average demand, calculated by averaging the maximum demand value for each half-hourly interval over the year, and maximum demand. Figure A.1.2 highlights that average total demand[53] has decreased significantly since 2010 in all jurisdictions except in QLD where a slight increase was experienced in 2015 and 2016. The overall trend in average demand suggests that factors including the growth in uptake of decentralised energy resources are reducing demand across most jurisdictions and that this trend is likely to continue into the future.

The difference between maximum demand and average demand across all jurisdictions is significant. The requirement for network investment to meet maximum demand and maintain the reliability of the network drives network expenditure, while network businesses' revenue depends on average demand over time which drives consumption levels. This mismatch creates challenges for network businesses as falling average demand leads to declining revenue without proportional decline in network expenditure. This challenge will require networks to respond effectively as demand patterns continue to change and the use of decentralised energy resources increase.

53 Total Demand is the underlying forecast demand at the Regional Reference Node (RRN) that is met by local scheduled and semi-scheduled generation and interconnector imports, excluding the demand of local scheduled loads and the allocated interconnector losses. Total demand and operational demand are not directly comparable as they have different definitions and operational demand is calculated by financial year, while total demand is calendar year. See AEMO's *Demand terms in EMMS data model*, published September 2016, viewed here: http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/2016/Demand-terms-in-EMMS-Data-Model_Final.pdf

Figure A.1.2 Average total demand by jurisdiction 2010-16



Source: AEMO

Daily peak demand

Daily peak demand for electricity differs for different consumers depending on weather, time of day, day of the week and so on. The time of most concentrated use of electricity is referred to as the peak. Traditionally peak demand periods could be forecasted with some accuracy however as the uptake of distributed energy resources increases, it may become more difficult to anticipate times of peak demand. Figure A.1.3 displays South Australia as an example of the changing nature of peak demand. In 2009 overall demand for grid electricity was higher. The trend was also different - peaking in the morning, remaining flat through the day before peaking again at night. In 2016 however peak demand for grid electricity is confined to the evening suggesting the growth in uptake in the use of DER especially solar PV is offsetting traditional peak times.

The changing patterns of peak demand will also require networks to adapt and respond effectively. As peak usage times alter, a requirement to maintain reliability of the network remains. As has been experienced recently in South Australia for example, while demand from the grid may decline at certain times of the day, network investment is still required to maintain a reliable and secure system. This challenge will be further exacerbated as the use of decentralised energy resources increase.

Figure A.1.3 Daily demand in South Australia, 2009 and 2016

Source: NEOpoint. Data is a snapshot of 30-minute operational demand for 10 February 2009 and 2016.

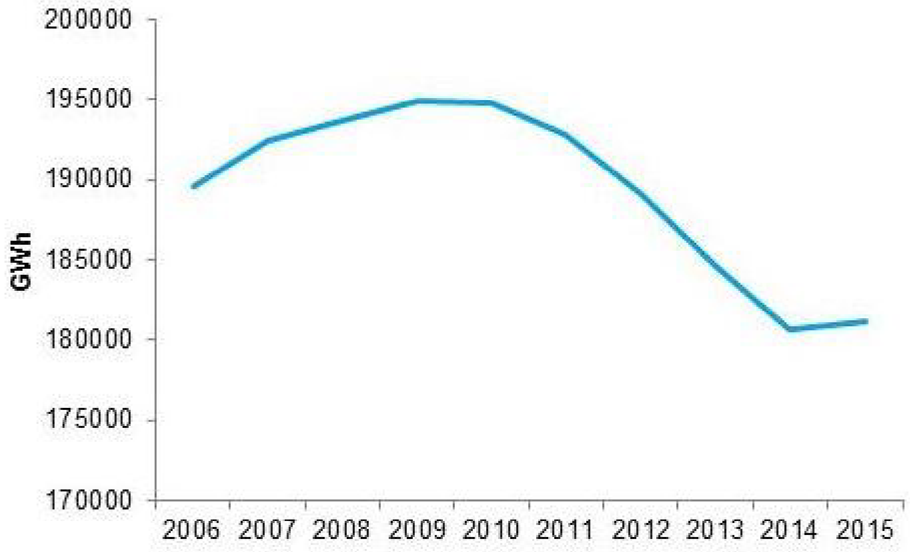
Trends in consumption

Similar to demand, operational consumption has declined since 2009, altering slightly in 2013-14. This trend is shown graphically in Figure A.1.4 below.

In the 2016 NEFR, AEMO has begun exploring trends in household electricity usage. This will be a useful indicator going forward to assess the changing consumption patterns from the grid in comparison with electricity being used in the home.

Changing consumer behaviour will continue to impact network investment into the future. Distributed energy resources and increasing use of energy efficient technologies will continue to create a divergent relationship between consumption from the grid and consumption in the home. It will be important that effective frameworks are in place to allow electricity networks to adapt and respond effectively in order to best utilise current and future investments while meeting consumer needs.

Figure A.1.4 Annual consumption 2006-2015



Source: AEMO

In future reports, the Commission will continue to use data from AEMO (including the NEFR) to monitor trends in maximum demand, peak daily demand, total demand and consumption.

Appendix 2 The changing technological environment

A.2.1 Introduction

Technology surrounding the grid is evolving. Traditionally, affordable electricity has been driven by economies of scale, with networks transmitting energy from large centralised power stations to households and businesses.[54] In recent years, though, more and more consumers have been adopting decentralised energy resources. New forms of generation, including solar PV and battery storage, are becoming cheaper and better - and as a consequence, more widespread and viable at a small scale. At the same time technological innovation is allowing for resources to be deployed and co-ordinated in unprecedented ways, giving rise to new forms of monetisation, trade and ownership.

These trends will change how the grid is used. More and more, networks will need to support two-way flows of electricity as well as integrating a range of other decentralised energy resources into their operations.

To a significant extent this transformation is being driven by consumers, though governments have also played a role through subsidies and other incentive schemes.

This chapter examines the development of decentralised energy supply over the past decade. Section A.2.2 examines the growth in decentralised energy supply (primarily solar PV). Section A.2.3 examines new business models, technologies and market platforms that are being developed in response to the increase in decentralised energy supply

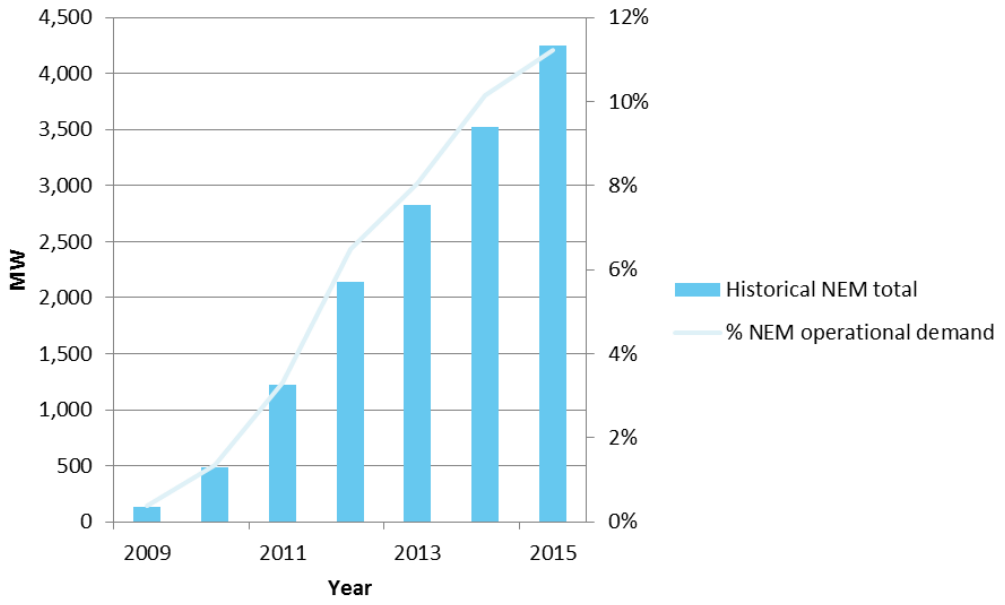
A.2.2 New forms of generation

A.2.2.1 Solar PV

Over the past decade, there has been a rapid increase in small-scale solar PV. Between 2009 and 2015, the installed capacity of small-scale solar PV in the NEM increased from 0.14 GW to 4.24 GW - a more than thirty-fold increase, and equivalent to over 10 per cent of maximum operational demand for that year. Most of this capacity has been installed in the residential sector, supporting the view that it is individual consumers and households who are driving transformation of the market. However, there has also been significant uptake by the commercial and industrial sectors. Figures A.2.1 and A.2.2 provide a graphical illustration of the growth in solar PV in the NEM.

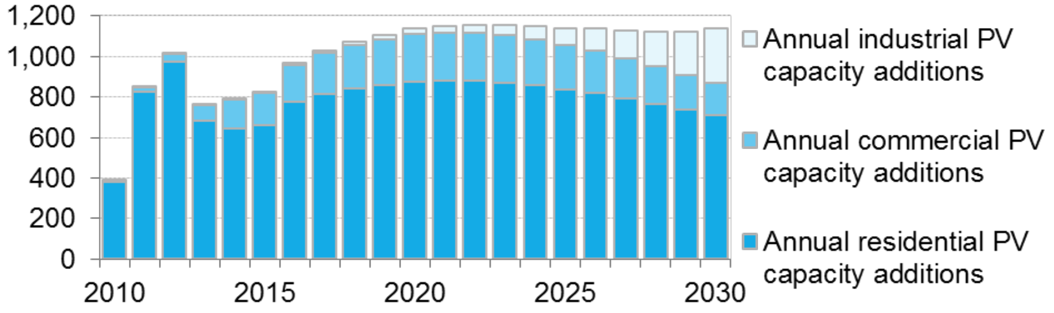
54 R. Hebner, 'The Power Grid in 2030', IEEE Spectrum (Volume: 54, Issue: 4, April 2017)

Figure A.2.1 Total solar PV capacity in NEM



Source: Bloomberg New Energy Finance

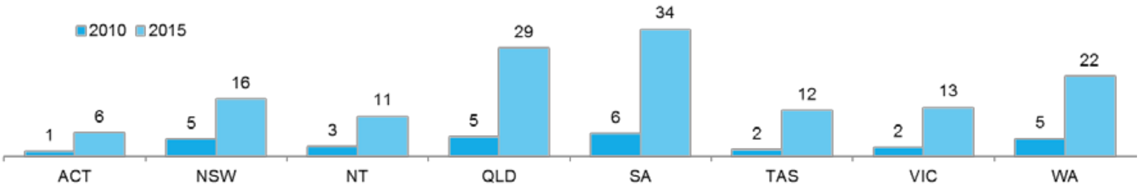
Figure A.2.2 Annual solar capacity additions by sector



Source: Bloomberg New Energy Finance

This growth has not been uniformly distributed across the jurisdictions, with some seeing a greater level of increase than others. The chart in Figure A.2.3 below shows that South Australia and Queensland experienced the highest growth in solar PV. Between 2010 and 2015, the percentage of South Australian households with solar PV grew from six per cent to 34 per cent while the percentage of Queensland households with solar PV grew from 5 per cent to 29 per cent.

Figure A.2.3 Residential dwellings with solar PV as percentage of total

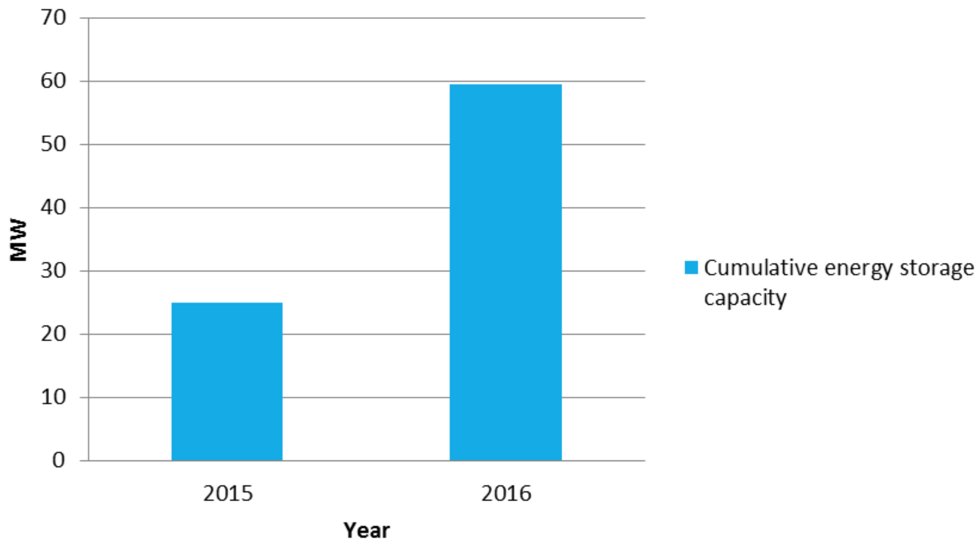


Source: Bloomberg New Energy Finance

A.2.2.2 Battery storage

While battery storage technologies are not new, their widespread use in the electricity system is a recent phenomenon. Despite extensive media attention, the current uptake of battery technology is relatively low, mostly because of cost.[55] However, the rate of growth in recent years has been rapid. In 2014, total battery storage capacity in the NEM was negligible. By 2015, it had grown to 25 MW, and by 2016 to 59 MW - more than doubling in the space of one year, albeit from a low initial base.

Figure A.2.4 NEM energy storage capacity 2015-16



Source: Bloomberg New Energy Finance

As with solar PV there are a variety of reasons why more consumers are starting to install battery storage. At a Clean Energy Council forum attended by staff members from the Commission, representatives from consumer groups spoke of people seeking greater self-sufficiency, wanting to reduce bills and to seek greater independence and protection from what were perceived as unpredictable price rises. At the same time,

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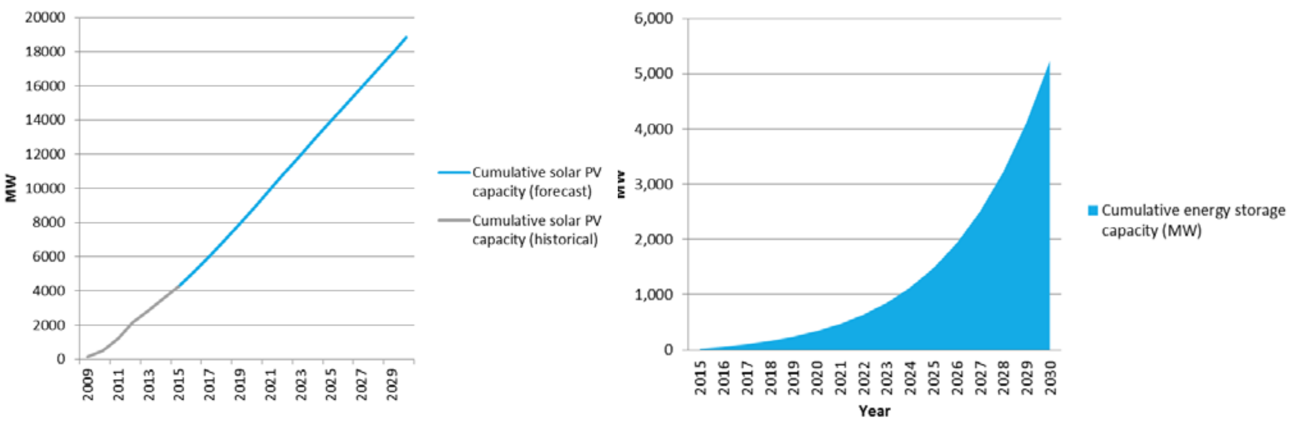
55 For example, see: Agarwal 2015, A Model For Residential Adoption of Photovoltaic System. Link: http://thesis.library.caltech.edu/8796/1/Agarwal-2015-master_thesis.pdf, accessed 2 March 2017.

policy shifts including the phasing out of generous feed-in tariffs have encouraged solar PV households to reduce their exports in favour of greater self-consumption of the electricity they generate. As is described in Chapter 4, networks are also starting to explore the use of batteries to provide network support, providing further opportunities for owners and investors.

Forecasts for the future uptake of both solar PV and battery storage tend towards the bullish. Bloomberg New Energy Finance, for example, predicts exponential growth in battery storage capacity across the NEM to 2030 as well as continued strong growth in solar PV.

Figure A.2.5 Forecast NEM-wide growth in battery storage and solar PV

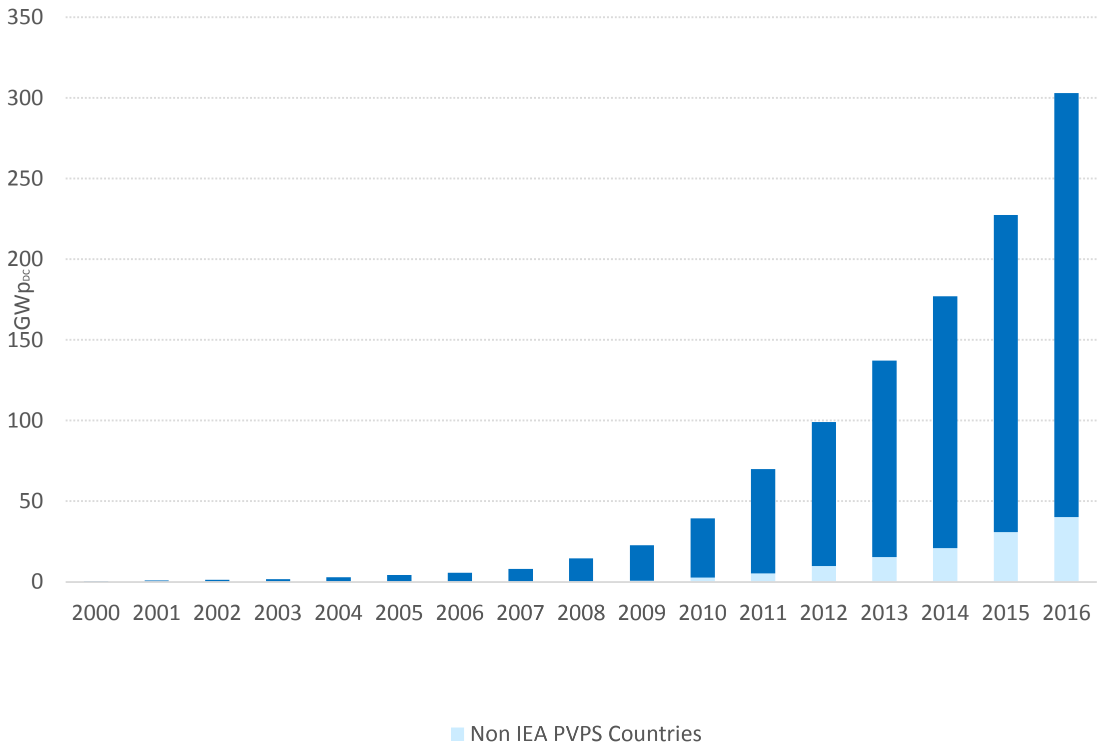


Source: Bloomberg New Energy Finance

Such forecasts are inherently uncertain and based on limited historical experience given the newness of the technology, particularly in the case of batteries. However, rapid growth has occurred in the past. Figure A.2.6 shows that solar PV has shown exponential growth in global capacity over at least the past decade. International agencies have historically underestimated the potential growth in uptake and fall in costs.[56] This is illustrated in Figure A.2.7.

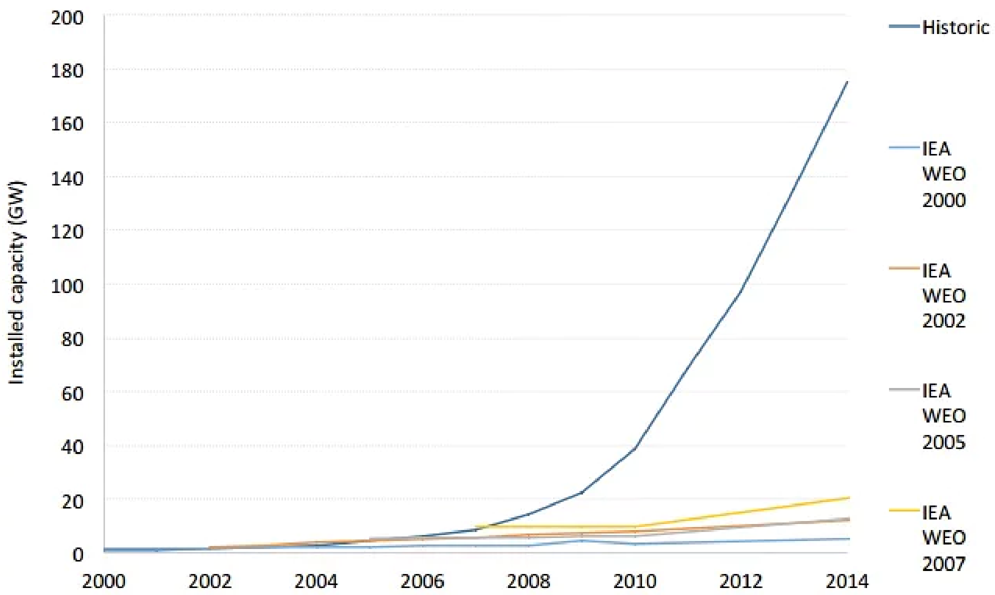
56 See for instance the International Energy Agency forecasts in Figure 2.6 below compared to historical capacity figures.

Figure A.2.6 Solar PV global installed capacity, 2000-2016



Source: © OECD/IEA 2016, '2016 Snapshot of Global Photovoltaic Markets', IEA Publishing. Licence: www.iea.org/t&c

Figure A.2.7 IEA forecasts versus actual growth in global solar PV capacity



Source: Data from International Energy Agency, graph by Carbon Tracker, cited from The Guardian

To a certain extent, trends in solar PV and battery storage uptake mutually support and reinforce each other. Solar PV households have an incentive to purchase batteries to store the excess power from when their home generation exceeds their consumption;

likewise, battery owners have an incentive to install solar so that they have self-generated energy to store. In addition, the market is evolving from a focus on PV only systems to integrated PV and storage systems (IPSS), often packaged with smart system controls that help to optimise the timing of energy discharge. The potential role of such 'energy management' systems, and other new technologies supporting decentralised energy resources, will be discussed in the next section.

Box 2.1 System security with new forms of generation

The widespread deployment of non-synchronous generating technologies, such as wind farms and solar panels, is having impacts on the operation of the power system. These technologies have low or no physical inertia, and are therefore currently limited in their ability to dampen rapid changes in power system frequency, which is needed in order to maintain a secure power system.

In each synchronous generating unit, the large rotating mass of the turbine and alternator has a physical inertia which must be overcome in order to increase or decrease the rate at which the generator is spinning. In this manner, large conventional generators that are synchronised to the system act to dampen changes in system frequency. In the electricity system, the greater the number of generators synchronised to the system, the higher will be the system inertia, and the greater will be the ability of the system to resist changes in frequency due to sudden changes in supply and demand.

Historically, most generation in the NEM has been synchronous and, as such, the inertia provided by these generators has not been separately valued. As the generation mix shifts to smaller and more non-synchronous generation however, inertia is not provided as a matter of course giving rise to increasing challenges for the Australian Energy Market Operator (AEMO) in maintaining the power system in a secure operating state.

In the *Managing the rate of change of power system frequency* rule change, the Commission has made a draft rule to place an obligation on Transmission Network Service Providers to procure minimum required levels of inertia or alternative frequency control services.

A.2.3 New technologies, business models and trends

A.2.3.1 Energy management systems

Many households and consumers have the ability to adjust their use of energy and devices to meet a certain goal, such as minimising bills or reducing pressure on the grid. This is particularly the case for households with solar PV and battery storage. However, they may lack knowledge or motivation to actually do so. Home energy management systems can help address this problem.

By changing the time at which they use electricity, consumers can have a significant impact on the network. Households which reduce their energy usage during the daily peak, or at the time of maximum demand in their part of the distribution network (for example, on the hottest day of the year) have the potential to significantly reduce network costs. This is also true of the owners of decentralised energy resources such as battery storage, who can relieve pressure on the grid by discharging at this time.

One of the tools that have been used by network businesses for some time in this fashion is the time of use (TOU) tariff structure. Under TOU tariffs, electricity is priced differently at different times of the day so as to better reflect the costs imposed on the network by using energy at different periods. Energy consumed during typical peak times incurs a greater charge than energy consumed during off-peak times, incentivising consumers to shift their usage. TOU tariffs are currently available in all jurisdictions of the NEM, although they can only be accessed by households with interval meters.[57] To date, however, uptake has been low. Surveys suggest that most consumers prefer traditional 'flat tariffs' to cost reflective pricing, partly due to risk-aversion and partly because of an unwillingness to spend time and energy responding to price signals.[58]

The low uptake of TOU tariffs points at larger barriers preventing households from optimising their energy usage in order to support the network. Choosing how to use (or not use) electricity based on network demand exerts a cognitive cost – learning how much electricity can be saved by turning on or off various different devices, knowing when intervals of high demand occur. Many consumers may not be willing to bear this cost.

There is therefore a role for devices which help consumers, and owners of decentralised energy resources, optimise their usage[59] with a minimum of effort. As the International Energy Agency writes:

> "Simple and scalable solutions have to be found so people can limit the time they spend on this to a couple of hours a year."[60]

A technological development which may help address these challenges is machine learning, or the use of algorithms that iteratively 'learn from experience' such as household energy consumption pattern data observed over time.

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57 Interval meters report measure electricity consumption in time intervals. Earlier models of interval meters report usage at 30-minute intervals and require manual reading. Under the 2015 *Competition in metering* rule change, new and replacement advanced meter must meet minimum specifications, which include a number of capabilities that can be accessed remotely in real time, and can be remotely read and operated.

58 Karen Stenner, Elisha Frederiks, Elizabeth V. Hobman and Sarah Meikle, 'Australian Consumers' Likely Response to Cost Reflective Electricity Pricing', June 2015. See http://cmd.org.au/wp-content/uploads/2015/08/CSIRO-Report-Consumer-Response-to-Cost-Reflective-Electricity-Pricing.pdf

59 These devices can potentially help customers optimise their usage and monetise a number of value streams. Some of these value streams include network support, retail bill optimisation and selling excess generation in the wholesale market.

60 International Energy Agency, 'Re-powering markets: market design and regulation during the transition to low-carbon power systems', 2016, p. 204.

Box 2.1 Energy management systems

A case study that demonstrates the use of machine learning to help consumers optimiase their energy use is the 'Reposit Box', a device designed by a Canberra-based startup to optimise performance of a home battery system. Reposit software is installed in the switchboard of a house that has battery storage and has two functions. First, it uses machine learning to combine information about the household's energy consumption patterns with expected solar generation based on weather forecasts, in order to maximise self-consumption and minimise bills. For example, if a cloudy day is forecast, the system may recharge from the grid overnight. Secondly, at times of high wholesale prices the Reposit software will sell surplus energy back to the grid, enabling households to maximise the economic return from owning battery storage.[61]

More generally, machine learning may be important in creating devices which help households to minimise their bills without requiring much user input. This will be important if these technologies are to expand their reach beyond energy enthusiasts and into the general population. In 2016, AEMO forecast that uptake of Integrated PV and Storage Systems (IPSS) would start slowly but increase in pace after 2020, reaching about 3.8GW installed by 2036.[62]

A.2.3.2 Aggregators

Commercial initiatives

Section A.2.3.1 above describes how households and consumers can help the grid, and potentially save or earn money, by changing the way they use electricity and as well as any decentralised energy resources they own. If these individual changes in behaviour can be aggregated and co-ordinated, the cumulative benefit for the grid could be much greater. While the transaction costs may be too high for an individual household to sell its services to the grid[63], it may become economic for a group of small entities to provide, for example, demand response once a certain threshold of impact has been passed.

61 Ecogeneration, 'Reposit adds brains to batteries and shaves dollars off bills', 29 November 2016. See http://www.ecogeneration.com.au/reposit-adds-brains-to-batteries-and-shaves-dollars-off-bills/

62 AEMO, 'National Electricity Forecasting Report', 2016, p 29.

63 Or for the network business to contract separately with individual consumers.

Box 2.2 Aggregators

AGL Virtual Power Plant

One scheme seeking to apply the energy-management techniques described in section A.2.3.1 on a large scale is the AGL Virtual Power Plant (VPP) trial. Partially funded by ARENA, this trial aims to aggregate a network of household and business-owned battery storage systems, in order to provide services such as peak demand management and frequency control. AGL states that the Adelaide-based trial, which uses cloud-connected software developed by the US company Sunverge, has already successfully linked more than 60 batteries, which together have stored and delivered over 10,000 kWh. Ultimately, the aim is to create a total of 7MWh of storage capacity and 5MW peaking capacity.[64]

Reposit

Likewise, Reposit says it has the capability to group consumers who have installed its software to form 'consumer power stations', which can provide services to the grid including network support.[65]

In the above cases, cloud-based technologies are being used to remotely link appliances and storage systems so that they can be operated in sync - part of the so-called Internet of Things. The potential impact of these schemes is significant, with demand reduction equivalent to the power output of a small industrial gas turbine (if the programs achieve their intended goals). This would have a material impact on the need for investment in the grid. Importantly, wide uptake of such cloud-based technologies will require infrastructure including fast and reliable Internet access, as well as means of managing the risk of cyberattacks. At a recent Clean Energy Council forum,[66] participants discussed ways to support a 'robust and secure' network. These included various security protocols to reduce the risk of attacks, and separating different functions so as to minimise the damage if the worst case scenario were to occur.

NSPs' initiatives

Some network businesses are also driving initiatives to aggregate the impact of multiple devices. AusNet Services has completed a small trial installing residential battery storage units at ten homes, which found that these could be useful for peak demand management depending on the level of capacity constraint on the network.[67] Similarly,

64 AGL, 'AGL's Virtual Power Plant Goes Live', 16 March 2017. See https://www.agl.com.au/about-agl/media-centre/article-list/2017/march/agl-virtual-power-plant-goes-live

65 From AEMC consultation with Reposit.

66 Clean Energy Council, Brisbane – Australian Energy Storage Leadership Series. See https://www.cleanenergycouncil.org.au/events/past-events/Brisbane-energy-storage-leadership-series.html

67 Essential Services Commission, 'The Network Value of Distributed Generation: Distributed Generation Inquiry Stage 2 Discussion Paper', June 2016. See http://www.esc.vic.gov.au/wp-content/uploads/2016/06/Distributed-Generation-Inquiry-Discussion-Paper-Network-Value.pdf

SA Power Networks is now running a mass trial of battery storage in an Adelaide suburb, offering subsidised batteries to homeowners with the aim of deferring or avoiding a potential $3 million upgrade of network capacity.[68]

A need for coordination

Early findings suggest that such trials need to be co-ordinated with other changes including pricing reform to maximise success. Under current tariff structures, there is an incentive to use batteries to reduce total demand (and therefore bills) but not peak demand or peak generation.[69] In addition, the high uptake of batteries may create new technical issues. In particular, rapid charging and discharging of batteries can cause strong fluctuations in voltage and make the 'ramp up' of demand on the network more rapid, again increasing costs. SA Power Networks has stated it may need to redesign some of its tariffs, so they incentivise battery vendors to configure their systems in a way that supports the network.[70]

A.2.4 New market platforms, ownership and trade

One consequence of decentralised energy resources becoming better, cheaper and more viable at a small scale is that there are fewer barriers to participating in the market. More and more it is becoming possible for consumers and households to attach a value to services which were previously not monetised, or only feasible for large entities to provide, and to sell these to the grid and to each other. The case studies in Box 2.3 below shows two of the new market platforms that are enabled by new technologies.

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68 SA Power Networks, 'Media release: SA Power Networks to conduct nation-leading trial of combined solar and batteries', 19 May 2016. See http://www.sapowernetworks.com.au/public/download.jsp?id=54883

69 As part of the Commission's consultation for this report, some NSPs have indicated that some sections of their networks are likely to require augmentation in the near future as high levels of excess solar energy exported by consumers are placing strains on network assets.

70 Giles Parkinson, 'Batteries not configured to remove demand peaks, network says'. Renew Economy, 27 March 2017. See http://reneweconomy.com.au/batteries-not-configured-remove-demand-peaks-network-says-64339/?utm_source=RE+Daily+Newsletter&utm_campaign=ceba3a2a56-EMAIL_CAMPAIGN_2017_03_27&utm_medium=email&utm_term=0_46a1943223-ceba3a2a56-40373949

Box 2.3 New market platforms

deX

deX, a scheme partially funded by ARENA and led by the startup GreenSync, seeks to create a digital marketplace for energy generated by solar panels and stored using batteries. The goal of the scheme, which is still at the pilot stage, is to enable households and small entities to 'rent' their decentralised energy resources to the grid, providing demand response and ancillary services such as frequency control. While the exact details of how the platform will operate are still to be determined, the approximate structure is as follows: participants will bid into a central marketplace, offering their services at a given price. DNSPs will then accept bids for services they require, starting from the lowest-priced and moving up until their need for demand response (for instance) has been satisfied. Importantly, the software being developed to facilitate these trades will be open source, which means that if successful it could be rolled out in markets round the world free of charge.[71]

Power Ledger

Power Ledger, a West Australian startup, is seeking to set up peer-to-peer energy trading for households and businesses with solar panels, potentially offering participants better rates for their solar energy than typical feed-in tariffs. Households that generate energy surplus to their own requirements will be able to sell it to other consumers - at a higher rate than a typical feed in tariff of 6 cents per kilowatt hour, but cheaper than a typical retail electricity price of 25 cents/kWh.[72] Some of this margin will go towards a network access fee[73], and presumably some will be allocated to Power Ledger to cover costs and a rate of return from running the platform.

A.2.4.1 Peer to peer trading

Peer to peer (p2p) trading of electricity is a relatively new concept that has yet to achieve major uptake, but is generating significant interest in markets round the world. While they remain largely hypothetical at this stage, significant benefits have been theorised. In a p2p system, households could purchase electricity directly from owners of small-scale distributed energy resources (DER) such as solar PV and batteries. Conversely, owners of DER could sell their output directly to other households rather than via a retailer or feed-in tariff.

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71 Jonathan Gifford, 'ARENA backs deX project to deliver open-source digital marketplace coupling distributed solar-plus-storage and grid services'. PV Magazine, 23 February 2017. See https://www.pv-magazine.com/2017/02/23/arena-backs-dex-project-to-deliver-open-source-digital-marketplace-coupling-distributed-solar-plus-storage-and-grid-services/

72 Power Ledger, 'Media Release: People Power!', 1 December 2016. See https://powerledger.io/progress, viewed May 2017.-

73 Cameron Jewell, 'Power Ledger sticks it to low solar feed-in tariffs', The Fifth Estate, 15 August 2016. See http://www.thefifthestate.com.au/energy-lead/power-ledger-sticks-it-to-low-solar-feed-in-tariffs/84075

To a certain extent, p2p markets in electricity represent an accounting exercise rather than a real physical trade. Electricity is not a tangible good. At point of consumption all electricity is functionally equivalent, regardless of whether it was nominally purchased from a neighbour or a distant large generator. However, this aspect is no different from existing arrangements in the market, where households (for example) purchase energy via a retailer which is linked to a particular mix of generation. By choosing one retailer over another, a consumer sends a signal for the relative amount of generation produced by that retailer's portfolio to increase. Similarly, by purchasing (for example) locally generated electricity on a p2p market rather than relying purely on 'traditional' markets, households would send a market signal for an increase in this type of generation.

Peer to peer trading of electricity requires the following four components to take place:

1. **Generating energy** - there needs to be a critical mass of households and other small-scale entities with DER.
2. **Proving identity** – there must be means to verify that participants in p2p trading are who they say they are.
3. **Transporting energy** – there needs to be a network or other means of transmitting energy from small-scale producers to consumers.
4. **Attributing consumption** – there must be reliable ways of determining how much energy each participating household has consumed, and will therefore be billed for.

Crucially, elements two and four are required in order to engender *trust*. Participants will be reluctant to transact with each other without a framework which gives them confidence that they are trading with legitimate entities, and that their agreements will be honoured. For example, if a consumer is paying another household to discharge their batteries at a certain time, they must be confident their payments really are going to that household, who will discharge their batteries as promised.

Blockchain

One technology that may turn out to be useful in surmounting the challenges described above is blockchain, which forms the basis of Bitcoin and other cryptocurrencies.

A blockchain is a digital ledger. It records the history of all transactions ever made in units of a particular resource, which are known as 'tokens'. Entries on the ledger assign ownership of a certain value of the resource, or number of tokens, to whoever holds the 'key'. This may in practice be an individual or business.

Due to the mathematical and cryptographical techniques used, as well as the fact that multiple copies of the data are held and stored by different users at any given time, it is either extremely hard or impossible to fake new entries to the blockchain ledger. The blockchain is also publically accessible and verifiable, meaning that anyone (with sufficient computing power) can audit the history of transactions. This makes it difficult to steal or fake anybody else's tokens, which engenders a high degree of trust.

For the purposes of p2p energy trading, some form of metering will be necessary to record electricity generated, imported or exported by participating households. Importantly, if p2p trading is to operate concurrently with existing markets, these units of energy will need to be recorded separately from electricity purchased via 'traditional' intermediaries such as retailers. This may require more sophisticated metering arrangements than are currently the norm.

Information regarding electricity generation, export and consumption will be converted into blockchain tokens, which will then be allocated between different participants based on the trades which have taken place. The blockchain tokens will then be exchanged for 'money' - either a cryptocurrency based on blockchain, or a 'traditional' currency such as Australian dollars. Both deX and Power Ledger intend to deploy blockchain technology to facilitate their platforms.

One feature of blockchain-based trading is that transactions can be verified by members of the public. This means that theoretically, a blockchain-based system could operate with little or no external oversight. For example, demand response and decentralised energy services could be traded directly between households and DNSPs. This could have the potential to save on third-party costs (assuming the cost of running the platform itself is relatively low.)

A.2.5 Microgrids

As small-scale energy resources grow in popularity, the grid itself is becoming more fragmented and less centralised.

A microgrid is defined as a group of interconnected loads and distributed energy resources, with clearly defined boundaries, which act as a single controllable entity and have no physical connection to the main grid. Microgrids have the potential to save money for communities which are geographically isolated, or which face particularly high charges for connecting to the main network for other reasons. There may also be non-financial benefits: greater resilience to natural disasters (as there is no reliance on one long power line which may be damaged by fires or storms, potential for greater reliability, satisfying consumer preferences associated with going 'off-grid' or independent.

The Huntlee Housing Development in the Hunter Valley presents one case study of a potential off-grid town. The suburb, which will house approximately 7,500 new homes and a commercial precinct, is planned to not connect to the network at all, and to be powered by a combination of rooftop solar PV, centralised battery storage, and a gas plant for backup. The cost of energy per lot is projected to be substantially lower than if the development were to connect to the national grid.[74] The project is being funded and implemented by a consortium including asset management company Brookfield and the developer LWP Property Group. ARENA has provided funding for a feasibility study.[75]

74 Off-Grid Energy Australia, 'Case Study: Off-Grid Town Huntlee Housing Development', viewed March 2017 at http://www.offgridenergy.com.au/wp-content/uploads/2016/12/Case-Study-HUNTLEE.pdf

75 ARENA, 'Media release: Making the case for energy-independent suburbs', 5 November 2015. See https://arena.gov.au/media/making-the-case-for-energy-independent-suburbs/

A.2.6 Who is driving these changes?

Innovation in technology, business models and other trends is being driven by a variety of actors. Stakeholders across the industry are participating in innovative projects. These include some DNSPs, both publically and privately-owned (Ausnet, SA Power Networks, ActewAGL), new and established retailers (AGL, Mojo Power), startups (Reposit, GreenSync, Power Ledger, Sunverge) and publically funded research (ARENA). In some cases, stakeholders are partnering and even forming large consortiums (deX, the Huntlee microgrid) to deliver complex projects requiring different forms of expertise.

The change is also being driven by consumers and their preferences. At an individual or household level there is considerable interest in new technologies and business models, which seems driven by factors broader than those traditionally defined as ‘economic’. At a Clean Energy Council forum, several stakeholders observed that the uptake of batteries (for instance) considerably exceeds what one would expect if consumers were purely focused on maximising their financial returns. Consumers are drawn to new technologies by a variety of motivations, which include: saving money, increased energy independence, protection against the vagaries of price fluctuations and policy change, wanting to 'do their bit' for environmental and other social causes, and simple interest and pleasure in trying new things.

Notably, a high proportion of the projects described in this chapter have received support from ARENA, the government agency tasked with pursuing innovation, and by funding from the DMIS. This suggests the transformation of the sector is being driven by policy as well as by consumers. In some cases, this has the advantage that any innovations or technological breakthroughs can be made freely available (for example, the open-source platform used for deX).

Also notable is that many innovations are coming from startups specialising in renewable energy and decentralised energy resources. The ongoing transformation of the sector may mean that such businesses play an increasing role in years to come, either through collaboration with existing retail and network businesses, or through means which do not sit neatly within traditional market models.

A.2.7 Role of regulatory framework

Technologies and business models supporting use of decentralised energy resources already exist and will continue to do so regardless of any governing regulatory framework. However, there is a role for the framework to play as a part of the 'partner state', supporting efficient innovation and efficiently allocating the inevitable risks that come with change.

In particular, three key functions of the regulatory framework will be:

- putting in place the **right incentives** for new technologies and business models to serve the interests of consumers;
- **protecting consumers from risks they are not best-placed to manage**, especially during the implementation of new technologies and schemes; and

- **coordinating investment and operation** of different distributed energy resources to get maximum benefits.

The role of the framework is discussed in greater detail in Chapter 4. A few additional notes on these points are presented below.

Implementation

Good communication and careful implementation can promote confidence and encourage effective participation by users of DER. Conversely, mistakes or imperfections in the initial rollout of any scheme can feed distrust which may inhibit uptake of similar technologies well into the future.

Under a well-managed rollout of any new scheme, participants will feel they can trust the companies and other entities they interact with, especially where financial transactions are involved. New technologies need not be fully *understood* by the majority of users to be widely deployed (see computers, electricity itself) but they must be *predictable*.

Ideally, consumers will understand their obligations and those of other stakeholders (retailers, networks, startups etc). They will be able to roughly predict the outcomes of their own choices (for example, engaging in demand response, or the costs and returns on investing in decentralised energy resources more generally). Trust and predictability may turn out to be especially important in the case of new tools, such as energy management software, which are not yet widely understood or familiar to most people. Effective, technology and business model-neutral consumer protections will help to build this trust.

Co-ordination

Incentives in different parts of the industry will need to be co-ordinated for new technologies, innovations and business models in networks to succeed. Ideally, incentives for consumers to install and deploy decentralised energy resources will be orchestrated with other prices and incentives in the market, sending efficient signals for future consumption and investment. For example (as in the SA Power Networks battery trial), price signals sent by retail tariffs need to be designed so as to take network costs and benefits into account. How this can ideally be achieved will depend on the shape of the distribution market in years to come. This question will be examined in more detail as part of the Commission's Distribution Market Model Review (ref: SEA0004).