# Electricity network performance report

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| 1.1 | 27/9/2021 | 83 | Update on page 61. |

# Contents

# 1 This network performance report

The 2021 electricity network performance report is the second annual network performance report for electricity networks. In it, we set out our analysis of key outcomes and trends in the operational and financial performance data we collect from electricity network service providers (networks). In forthcoming years we plan to prepare similar reports for the full regulated gas pipelines, commencing with a report on the gas distribution networks due later this year.

This report includes data for electricity distribution network service providers (DNSPs) and transmission network service providers (TNSPs). The analysis is focussed on the provision of core regulated services. These are:

- Standard Control Services for electricity DNSPs, and
- Prescribed Transmission Services for electricity TNSPs.

These are ordinarily the key transport of energy services that the networks provide with their assets included in the regulatory asset base. Networks do provide and collect revenue for other services, but these sit outside the revenue cap, are subject to other forms of regulation and, in some cases, are unregulated.

We encourage stakeholders to read this report alongside our annual benchmarking report which reports on the networks’ productive efficiency.

## 1.1 Key findings

Our 2021 electricity network performance report shows that network regulation is improving outcomes for consumers. It highlights the impacts of improvements in our regulatory tools over recent years, but also highlights areas where further work is required.

Specifically, our key findings in this report are that:

- Network revenue is continuing to decline. We expect this decline to continue in the next few years as the impacts of our 2018 rate of return instrument take effect in a lower interest rate environment.
- Despite this, networks continue to be profitable and generate returns above our forecasts despite impacts of COVID-19 during the regulatory year. This reflects a range of different drivers including financing strategies and spending less than our forecasts across different revenue building blocks.
- COVID-19 changed patterns of electricity consumption. In 2020, this was most pronounced in Melbourne and in Victoria more generally.
- Customers are, on average, experiencing fewer but longer outages—measured by SAIDI and SAIFI.
- Both frequency and duration of unplanned network outages vary materially between seasons and between customers on different feeder types.

## 1.2 Focus areas

To make the report accessible and useful for a range of stakeholders with varying levels of experience with our regime, we have tried to strike a balance between:

- regular high-level reporting on a core set of measures, and
- more detailed analysis on emerging issues of interest to stakeholders.

For this report, our focus areas are:

- The impact on networks and network consumers of COVID-19
- Better understanding the seasonal dynamics of network reliability
- Introduction of the return on regulated equity (RoRE) profitability measure
- Network safety.

In developing this report, we engaged with stakeholders to test views on important focus areas. Our intention is to choose new and relevant focus areas each year to reflect important emerging issues and stakeholder interest. To best target those choices, we encourage direct feedback on topics or emerging issues of interest. In section 8 we identify some potential focus areas for future reports.

## 1.3 Stakeholder engagement on the report

Prior to developing the report, we have had extensive stakeholder engagement to:

- Develop our priorities and objectives for reporting on network performance
- Complete our profitability measures review, which has been an important input into this report

In developing this report, we:

- sought early input from a cross-section of consumer and industry stakeholders on our focus areas for the report
- gave NSPs an opportunity to review the accuracy of our key data-sources
- gave NSPs and consumer representatives an opportunity to review and engage with our analysis. We will continue to undertake this consultation for future reports
- engaged with state and territory safety and technical regulators on the accuracy of the safety and reliability analysis within the report. The input we received will be useful in planning future reporting and we intend to continue engaging with these regulator

# 2 Contents and structure of the report

## 2.1 The objectives of this report

Through this report and the accompanying data, we intend to advance the network performance reporting objectives, determined with the input of stakeholders.[1] These are set out in Table 2.1.

### Table 2-1 How we are advancing our objectives for network performance reporting

| Objective | What we are doing |
|---|---|
| Provide an accessible information resource | We have drafted this report with the intent of making it both informative and accessible for stakeholders. Alongside this report we have published two data models covering:<br>• Our operational performance data.<br>• Our financial performance data.<br>These cover much of the data captured in this report at a greater level of detail. We aim to present the data in a form that enables stakeholders to use it in their own analysis.<br><br>In addition to these data resources, we have undertaken a survey of publicly available reporting on electricity network safety and have summarised our findings as a resource for stakeholders. |
| Improve transparency | Through the report and our published data, we are trying to illustrate the impacts and interactions of network performance under different regulatory tools or settings. The regulatory regime can be complex. Our objective through this reporting is to make network regulation and its outcomes more transparent for stakeholders. For example, in this report we have reported on seasonal reliability outcomes to show a more comprehensive picture of network reliability compared to what is available from annual aggregated data. |
| Improve accountability | The focus of this report is on the effectiveness of network regulation as a whole, increasing our accountability for regulatory decisions, and for the networks and their performance under those decisions. Further, our published data allows for comparisons of individual networks and, in our published data and analysis, we highlight particular areas where particular networks depart from broader trends. |
| Encourage improved performance | Similarly, by improving accountability and transparency we expect that these reports over time will contribute to improved performance by:<br>• Informing ourselves and stakeholders about emerging trends which may require a regulatory response.<br>• Contributing to the incentives on NSPs to improve performance.<br>• For example, in this report we have set out analysis of the relationship between utilisation and reliability to inform our thinking on whether those networks with greater aggregate spare capacity are producing better reliability outcomes. |
| Inform consideration of the effectiveness of the regulatory regime | Our analysis in this report is intended to support consideration of how the regulatory regime contributes to network performance and outcomes. We aim in particular to explore where actual outcomes depart from forecasts or trends, whether this is widespread and what implications that has for our regulatory approaches. |
| Improve network data resources | In this report, we have introduced the new return on regulated equity profitability measure.<br><br>Further, through our analysis of the data, we have sought to:<br>• Investigate and make use of a wide range of our network data sources. |

[1] AER, *Objectives and priorities for reporting on regulated electricity and gas network performance—Final*, June 2020.

| | |
|---|---|
| | • Identify and manage differences in reporting which impede comparability of data provided by different NSPs.<br>• Identify important questions on which we would like to form views but are limited by data availability or consistency.<br>• Over time, we expect this approach will also assist us to form a view on any data we currently collect which may be excessive or not useful. |

Source: AER analysis

We encourage stakeholder feedback on the report and our accompanying data resources so that we can improve its usefulness over time. Following release of the report, we encourage input from stakeholders by emailing networkperformancereporting@aer.gov.au.

## 2.2 The structure of this report

In our view, an effective network regulatory regime contributes to consumers paying no more than is necessary for safe and secure supply of energy.

Implicit in this vision is a balance between the costs of providing network services and the outcomes arising from those costs. We have structured the report to address a series of questions that we believe, should assist us and stakeholders in reaching a view on whether this balance is being achieved. We have also sought to link these questions back to our performance reporting priorities, determined with the input of stakeholders.

The structure of the report is set out in Table 2-2.

**Table 2-2 The structure of this report**

| Section | Contents | Network performance reporting priority |
|---|---|---|
| 1 | This network performance report | n/a |
| 2 | Key findings | All |
| 3 | Electricity network performance in 2021 | Operational performance and efficiency<br>Financial performance |
| 4 | Focus area—Impact of COVID-19 on energy consumption and revenue | Operational performance and efficiency<br>Financial performance |
| 5 | Focus area—Seasonal reliability | Operational performance and efficiency |
| 6 | Focus area—Survey of network safety reporting | Operational performance and efficiency |
| 7 | Focus area—Introduction of the return on regulated equity measure | Financial performance |
| 8 | Looking ahead to 2022 | Emerging issues |

Source: AER analysis.

## 2.3 How we refer to regulatory years

This network performance report covers network data for regulatory year 2020 which is:

- July 2019–June 2020 for financial year NSPs (all except Victoria)

- May 2019–April 2020 for AusNet Transmission (Victoria)
- January 2020–December 2020 for Victorian DNSPs[2]

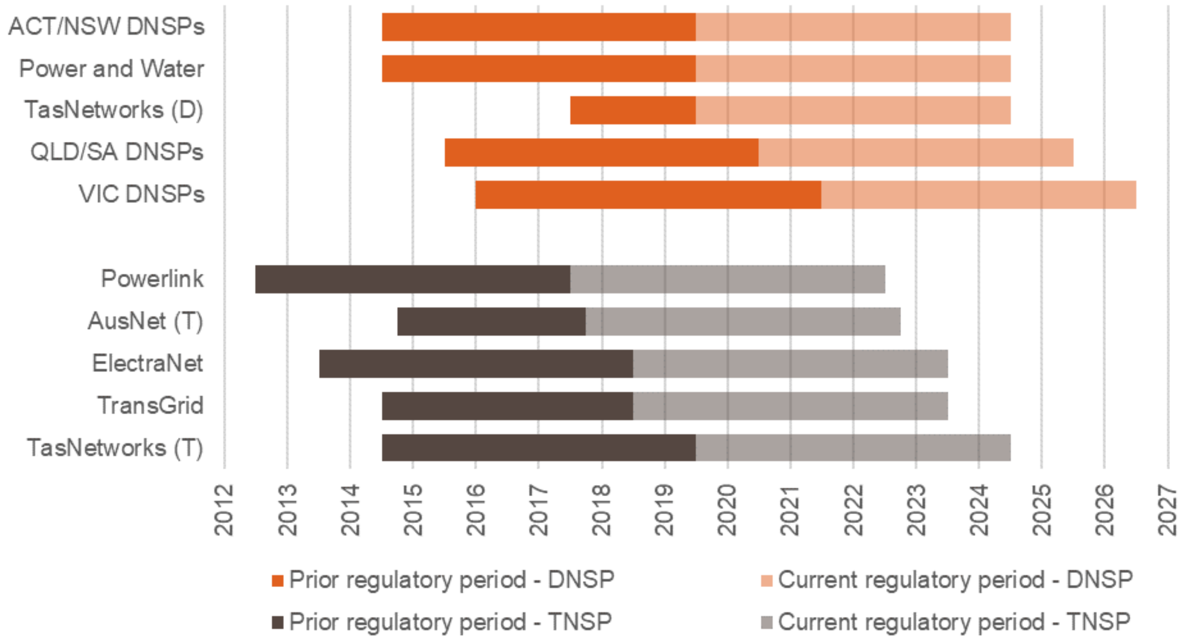
This is our naming convention wherever we refer to specific regulatory years in this report. So, for example, regulatory year '2016' refers to 2015-16 for a financial year NSP and 2016 for a calendar year NSP.

## Where 2020 sits in the regulatory cycle

Generally, our regulatory determinations apply over 5 year periods. We make these decisions for regulated NSPs in a staggered cycle over time.

An important consequence of this approach is that changes in regulatory approaches or market conditions feed gradually into network determinations.

**Figure 2-1 The staggered revenue decision timetable**




Source: AER analysis.

Note: The Victorian Government has legislated a 6 month extension to the timing of determinations for Victorian DNSPs which would otherwise have commenced in January 2021. Under this change the previous regulatory period was extended to finish on 30 June 2021 and the full five year regulatory period will commence on 1 July 2021.

For convenience, we think of regulatory cycles as commencing with the determinations for a large number of the DNSPs, including those in New South Wales, Australian Capital Territory, Tasmania and the Northern Territory. The determinations for those networks have over time been the first

2 Note: The Victorian Government has legislated a 6 month extension to the timing of determinations for Victorian DNSPs which would otherwise have commenced in January 2021. Under this change the previous regulatory period was extended to finish on 30 June 2021 and the full five year regulatory period will commence on 1 July 2021.

major decisions to incorporate substantial changes in regulatory settings (2013 better regulation; 2018 rate of return instrument).

Regulatory year 2020 is the first year of new regulatory periods for DNSPs in New South Wales, the Australian Capital Territory, the Northern Territory and Tasmania as well as Tasmania's transmission network.

## 2.4 Reporting on Northern Territory Power and Water Corporation

In 2019 we made our first determination for Northern Territory Power and Water Corporation (NT PWC), the Northern Territory's electricity distribution network. 2019-20 (regulatory year 2020) is the first year of its first regulatory period under an AER determination. Unless otherwise specified in the report, we have included NT PWC data in our report. In some cases where data series are relatively simple—for example historical RAB trends—we have included historical NT PWC data to our existing data series for continuity through time.

# 3 Summary of electricity network performance in 2020

In this section, we set out a summary of outcomes in core performance measures covering:

- Network revenue—the cost to consumers of network services
- Network expenditure
- Network service outputs
- Network profitability

We have focussed in this summary on:

- Outcomes in 2020 and how they relate to longer term trends across these network performance measures
- Where relevant, how those outcomes compare to forecast amounts

Our analysis in this section supports analysis of, but does not directly answer the question of whether the relationships between network expenditures and service outputs are productively efficient. Our benchmarking reports for distribution and transmission networks, due to be published in late-2021, use a range of econometric tools including economic benchmarking to measure how productively efficient these networks are at delivering electricity distribution and transmission services over time and compared with their peers.

The costs and profitability of network services are by-products of the networks' productive efficiency, capital market conditions and of our regulatory settings, including the way that we forecast expenditure and the way that we share the rewards or penalties of network performance between networks and consumers.

All analysis in this section is in real 2020 dollar terms, unless otherwise noted.

## 3.1 Network revenue—the cost to consumers of network services

To assist stakeholders in forming a view on whether consumers are paying no more than is necessary for safe and reliable supply of electricity, we have first set out some analysis on what they have spent on core regulated services.

The proportion of total revenue collected from different types of consumers varies between networks and over time. Also, most electricity consumers pay network costs via a retailer, in which they are combined with other costs of supplying energy. This means it can be complex to make general observations about the impact of network costs on specific consumer bills. However, the total revenue that networks recover is an informative measure of how core network services are contributing to consumers' bills.

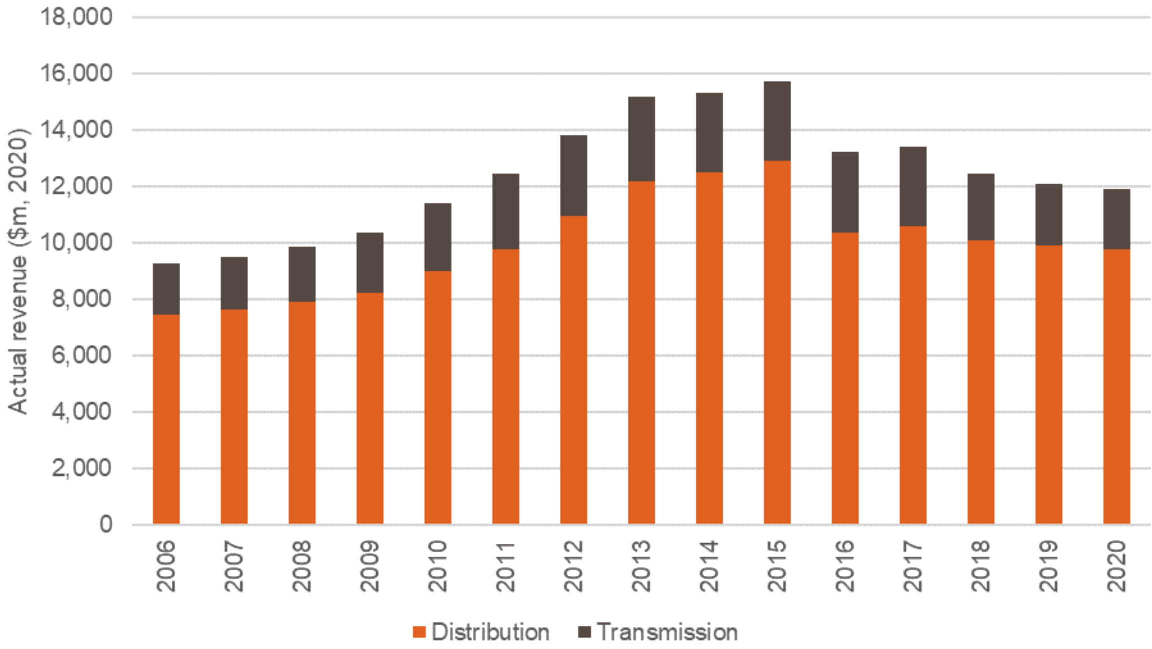
Electricity DNSPs are also responsible for collecting from consumers other costs, such as the costs of jurisdictional schemes, which we do not have a role in setting. Some of these schemes, such as jurisdictional solar bonus schemes, are not included in the revenue building blocks. For the purposes of this section, where we refer to 'network costs' we have focussed our analysis only on those costs arising from:

- DNSPs providing standard control services (SCS), and
- TNSPs providing prescribed transmission services

## Actual network revenue

In 2020, customers spent less on electricity network services than they have at any time since 2011 (Figure 3-1).

**Figure 3-1 Total core regulated network service revenue recovered from consumers – DNSPs and TNSPs**




Source: Operational performance data, AER analysis.

Note: These are the total actual SCS and prescribed transmission service revenue amounts collected from consumers, as opposed to annual target revenue, the smoothed PTRM revenue target or the unsmoothed building block revenue total.

This downward trend in network revenue means that consumers are paying less for the network component of their bills. Consumers' bills are also made up of several other components, also including wholesale market costs, retail margins and jurisdictional costs. Further information on these other bill components is set out in our State of the Energy Market report, and in our regular wholesale and retail reporting.

## Drivers of network revenue

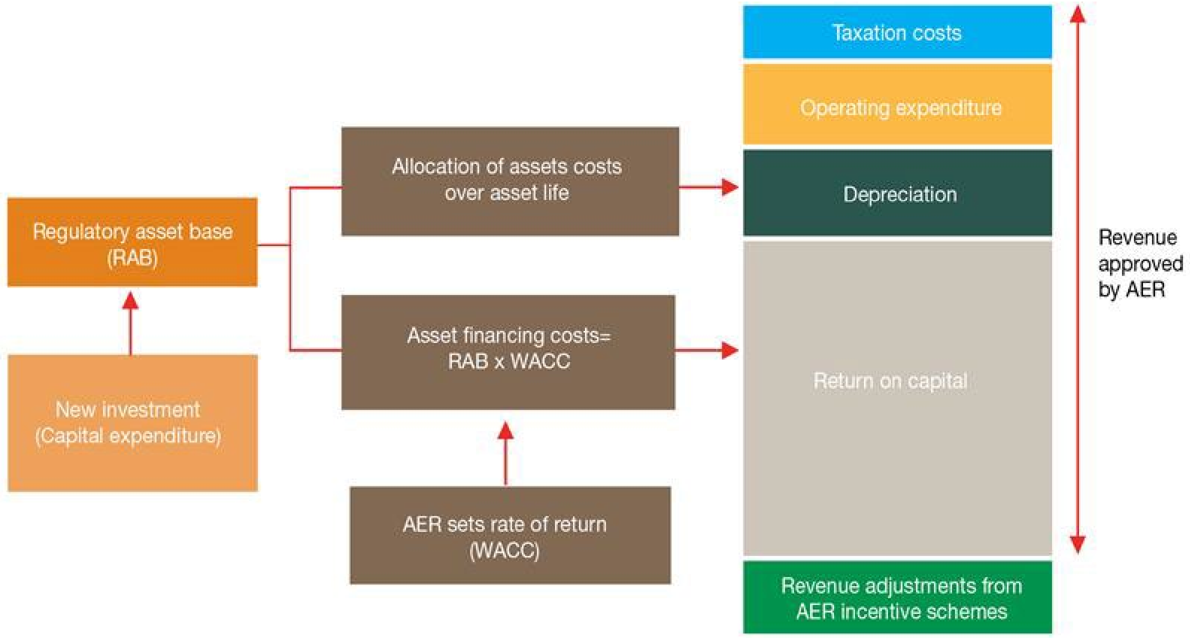
All electricity networks are now regulated under revenue caps.[3] Networks annually set their charges to target a total revenue amount determined under the revenue cap. The key drivers of

3 The last network to be moved to a revenue cap was Evoenergy at the commencement of its 2019-24 regulatory period.

the revenue target are set in our revenue determinations so NSPs can recover the costs an efficient network would require to provide core regulated services. These are determined as a series of ‘building blocks’, including:

- a return on the RAB (or return on capital, to compensate investors for the opportunity cost of funds invested in this business)
- depreciation of the RAB (or return of capital, to return the initial investment to investors over time)
- capex — the capital expenditure incurred in the provision of network services — mostly relates to assets with long lives, the cost of which are recovered over several regulatory control periods. The forecast capex approved in our decisions directly affects the projected size of the RAB and therefore the revenue generated from the return on capital and depreciation building blocks
- forecast opex—the operating, maintenance and other non-capital expenses incurred in the provision of network services
- the estimated cost of corporate income tax
- revenue adjustments, including revenue increments or decrements resulting from the application of various incentive schemes.

**Figure 3-2 The building block model to forecast network revenue**




Source: AER, State of the Energy Market, December 2018, p.138.

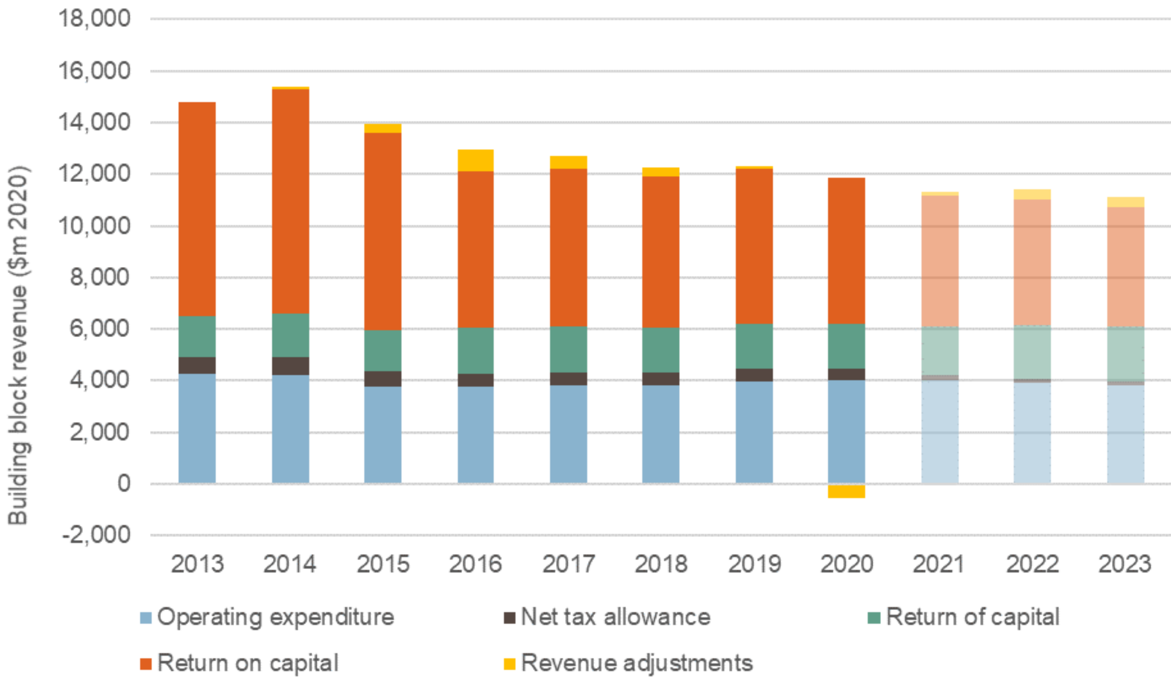
We also update the revenue target each year to account for actual inflation, changes in the networks’ required returns on debt, cost-pass throughs and other factors.

In 2020:

- Forecast network revenue continued to decline driven largely by declining forecast returns on capital (Figure 3-2).
- A further one-off decrease reflects the impact of material revenue adjustments. These arose as a result of temporary circumstances in place during reviews by DNSPs in NSW and ACT of our 2014-19 determinations under the limited merits review framework, and subsequent judicial review appeals to the Full Federal Court.

We expect the declining trend in revenue to continue further in years to come as the impacts of the 2018 rate of return instrument and 2019 tax review feed into the forecast return on capital and tax building blocks.[4] This depends to some extent on prevailing interest rates in debt market which flow through to revenue allowances through our annual updates.

**Figure 3-3 Trends in forecast building block revenue components — DNSPs and TNSPs**




Source: PTRMs, AER analysis

Note: Powerlink and AusNet (Tx) revenue determinations are not yet complete for the 2022-23 regulatory years. This chart includes forecast revenue from their initial proposal PTRMs.

## Incentive Schemes

The regulatory framework is an incentive based framework. In addition to the inherent incentives within the regime, we apply a series of targeted incentive schemes. These schemes are important

4 The impact of allowed rates of return on networks was discussed in detail in last year's report.

regulatory tools designed to encourage desirable behaviours by the networks (namely to improve efficiency and reliability) which in turn will deliver better outcomes for consumers and promote achievement of the national electricity objective (NEO).[5]

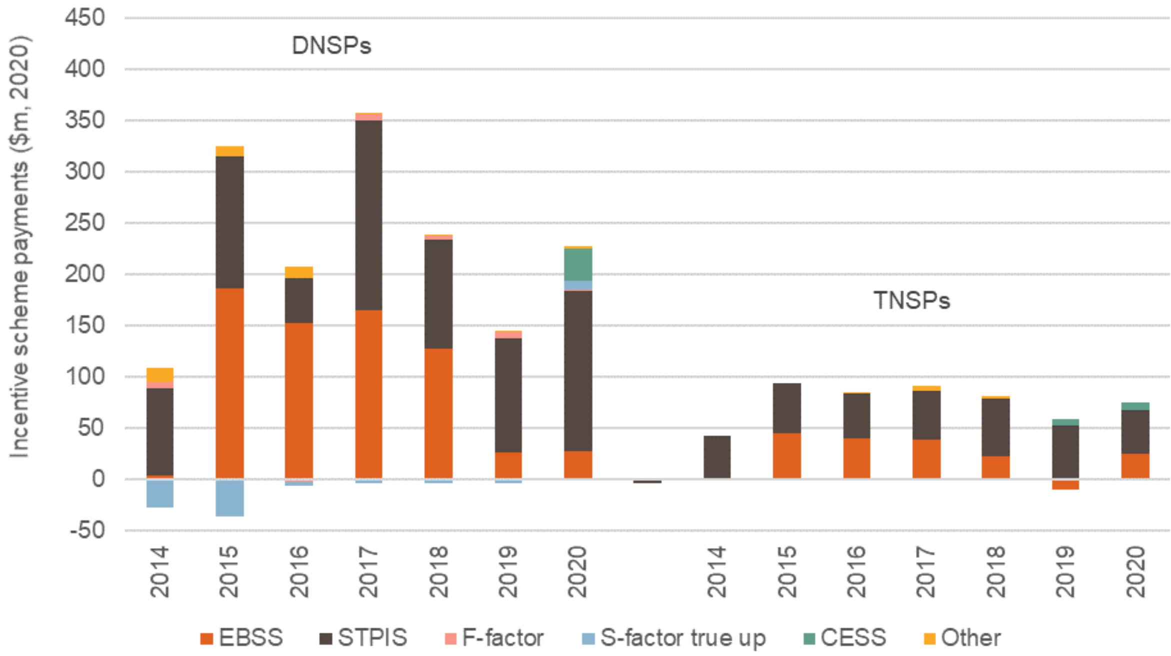
In 2020:

- DNSPs and TNSPs both received more in incentive scheme payments than 2019
- The majority of incentive scheme payments were from the STPIS
- Both DNSPs and TNSPs are beginning to report payments under the CESS. These CESS amounts are likely to increase as more networks enter new regulatory periods

To date, networks have received incentive scheme rewards or penalties under the following schemes:

- efficiency benefit sharing scheme (EBSS)
- service target performance incentive scheme (STPIS)
- demand management incentive scheme for the DNSPs
- F-factor scheme for the Victorian DNSPs
- capital expenditure sharing scheme (CESS)

**Figure 3-4 Composition of reported incentive scheme payments**




Source: Economic benchmarking RIN responses, Post Tax Revenue Model and AER analysis.

5 Incentive schemes were a focus area in last year's report. This investigated the impact of revenue on the networks' revenue allowances.

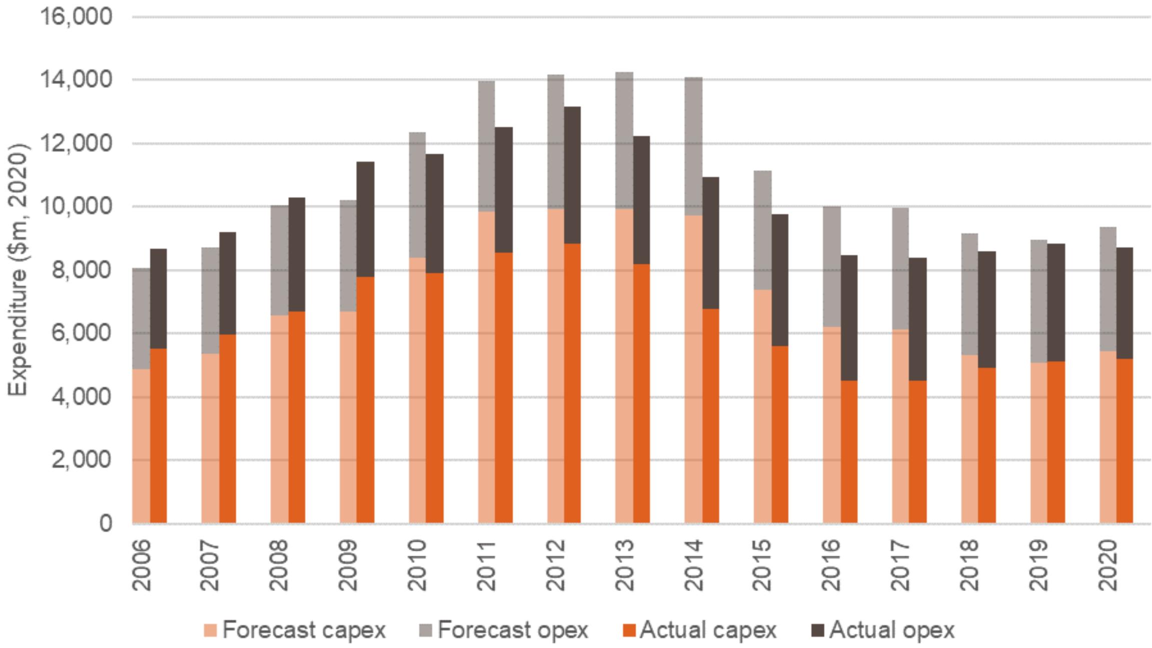
## 3.2 Network expenditure

With the revenue collected from consumers, networks undertake operating and capital expenditure in whichever way they determine to be most efficient in order to result in safe and reliable supply of electricity.

In 2020:

- Networks overall spent less opex and less capex than they did in 2019
- This occurred despite forecast increases in both opex and capex.

**Figure 3-5 Total Expenditure – DNSPs and TNSPs**




Source: Operational performance data, AER analysis

These overall outcomes are materially impacted by outcomes amongst several networks.

### NSW DNSP expenditure

This aggregate result in 2020 is driven in large part by reductions in both opex and capex by the NSW DNSPs. For example, when comparing actual capex in 2020 against forecast capex:

- Ausgrid, Endeavour Energy and Essential Energy spent a combined $213m (14%) less than forecast capex in 2020
- All other electricity networks together spent a combined $69m (2%) less than forecast capex in 2020.

Similarly, when comparing actual opex in 2020 against forecast opex:

- Ausgrid and Endeavour Energy spent a combined $132m (17%) less than forecast
- All other electricity networks together spend a combined $238m (8%) less than forecast.

Ausgrid, Endeavour Energy and Essential Energy were all in the first year of their 2019-24 regulatory control period.[6] We observed in the 2020 report that most DNSPs in recent regulatory periods spent well below forecasts in the early years of those periods and close to or above forecast capex late in the periods. We recognise that for any particular network there are potentially a range of network-specific factors impacting expenditure in a given year. However, this is not what we would expect under the design of the CESS. Amongst other things, the CESS is designed to create an even financial incentive for efficiency gains through the regulatory period.

In engagement, the networks identified factors that they consider have contributed to 2020 expenditure outcomes, including disruptions caused by COVID-19. We will continue to consider these results in the context of broader trends across the sector and through time.

## Ergon Energy capex

We also observe that Ergon Energy spent $188 million more than forecast capex in 2020. Notably, this was $187 million more than was estimated as final year capex included in the roll-forward model as part of our 2020–25 determination for Ergon Energy.

The materiality of this underestimate in final year capex is unusual and contributed to two distinct effects on revenue for the 2020-25 regulatory control period:

- a higher reward under the CESS than would otherwise have occurred
- a lower opening RAB, and hence lower return on capital and depreciation forecasts than would otherwise have occurred.

In engagement, Ergon Energy attributed this variance to replacement of ageing assets, in turn arising from a change in its asset inspection processes. It indicated that this information not being included in its estimate of final year capex was due to a process oversight.

The offsetting impact of the two effects means that there is relatively little impact on Ergon's revenue in this regulatory period. Both effects will be trued up at the next regulatory determination. In particular, we expect a downward revision in Ergon Energy's CESS rewards in its next regulatory control period.

## First year of NT PWC expenditure outcomes

In addition, 2020 was the first year in which NT PWC was regulated under an AER determination. We observe that NT PWC:

- spent approximately $22m (24%) less than forecast capex

6 As outlined in section 2.3, '2020' for the NSW networks is 2019-20.

- spent approximately $21m (30%) more than forecast opex

We will continue to monitor NT PWC's expenditure outcomes in years to come to monitor whether this pattern persists and, if so, its implications.

## 3.3 Regulatory asset bases

Regulatory asset bases (RABs) capture the total economic value of assets that are providing network services to consumers. Over time, the RAB grows as networks undertake capital expenditure. Consumers pay the costs of raising that capital through the return on capital and return of capital (depreciation) allowances. We also inflate the RAB each year to reflect the impacts of inflation. This increases the nominal value of the assets in order to maintain its real value through time.[7]

These assets have been accumulated over time and will be at various stages of their economic lives. Some networks may be relatively older or younger than other networks depending on their growth and their phase of the replacement cycle.

The value of the RABs substantially impacts networks' revenue requirements, and the total costs network consumers ultimately pay.

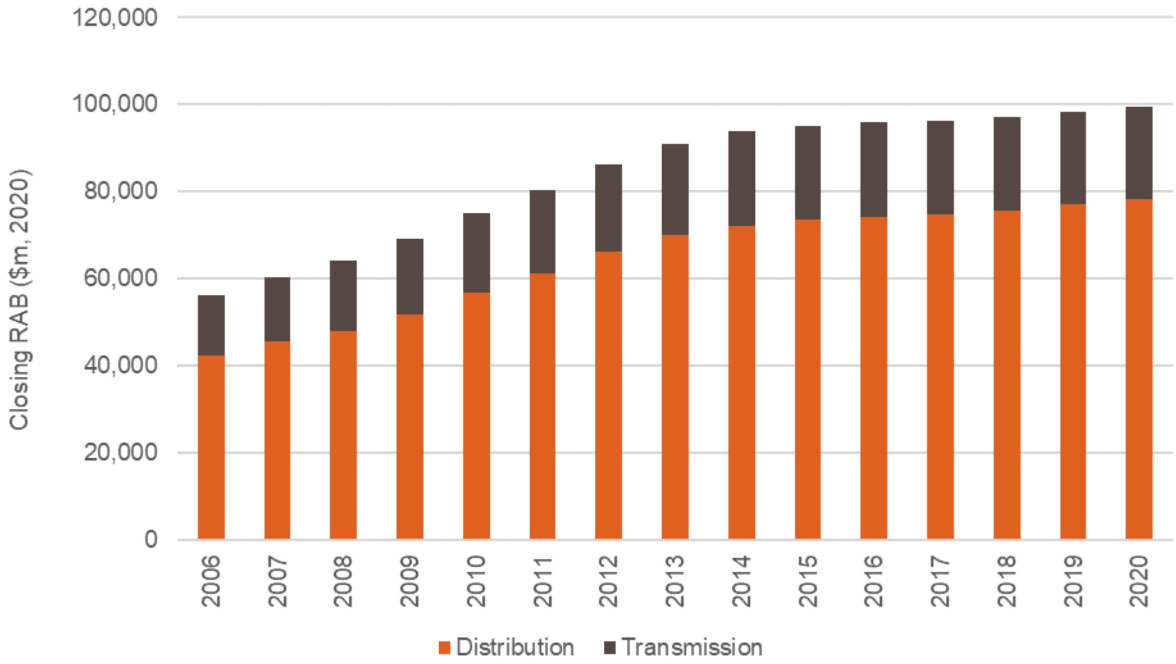
### Total RAB growth

In 2020:

- The total real value of regulatory asset bases increased slightly on 2019, in line with recent gradual growth in the RAB
- This is the combination of:
  - 3% growth in distribution network RABs
  - a very slight (0.2%) decline in transmission network RABs
- Annual aggregate real RAB growth has been approximately 2% per year since 2015, compared to 8% per year over 2008-14

7 The indexation of the RAB is explained on our website, available on our website here.

**Figure 3-6 Real RAB values – DNSPs and TNSPs**



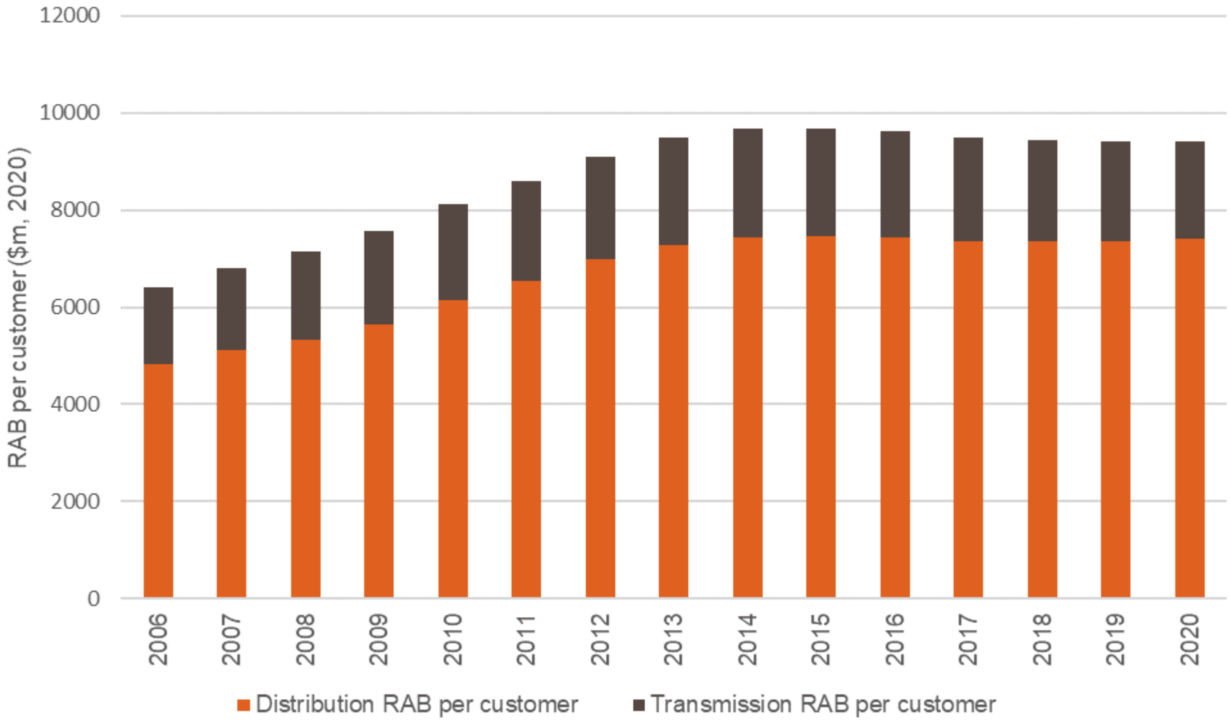

Source: Operational performance data, AER analysis.

In recent years, capital expenditure has been lower than in previous regulatory periods. Though there has been a material reduction in actual capital expenditure since 2014, depreciation since 2014 has remained relatively steady. This is because of the accumulated impact of historical investments and because of the straight-line depreciation approach we use, which returns capital evenly over the life of an asset. As a result, real RAB growth has slowed. In the case of some transmission networks, RABs have recently declined in real terms.

## RAB per consumer

It is also important to note that growing RABs do not necessarily result in growing capital costs per consumer if either the rate of return on capital is declining or the consumer base is growing. Both are currently the case. Over 2014 to 2018, consumer numbers grew faster than real RABs, resulting in a levelling and occasionally declining average RAB per customer. In 2019 and 2020, RAB per customer has returned to incremental growth.

**Figure 3-7 RAB per customer – DNSPs and TNSPs**




Source: Operational performance data, AER analysis.

## 3.4 Network reliability

A key outcome that consumers should expect for their investment is a reliable supply of electricity. In this context, reliability refers to the continuity of electricity supply and is typically measured by the frequency and duration of interruptions to supply.

While consumers value a reliable electricity supply, maintaining or improving reliability may require expensive investment in network assets. As a result, there is a trade-off between electricity reliability and affordability. Reliability standards and the incentive schemes need to strike the right balance by targeting reliability levels that consumers are willing to pay for.

We collect and report data on reliability and utilisation for both DNSPs and TNSPs. For this report, we have focussed our analysis on DNSPs, recognizing that most supply interruptions originate there. Through our reporting over time, we will capture a balance of distribution and transmission network service outcomes.

We report on both:

- The frequency and duration of unplanned outages which we determine under our service target performance incentive scheme (STPIS) to be within the network’s control at their funding levels. This will exclude some outages, including some major events that are part of the total unplanned outages. We refer to these as 'normalised' measures of reliability:
  - SAIFI (System Average Interruption Frequency Index) measures the average number of interruptions a consumer experiences each year.

- SAIDI (System Average Interruption Duration Index) measures the average duration (minutes) of interruptions a consumer experiences each year.

- Unplanned outages excluded from SAIDI and SAIFI including major events such as storms, fires, floods and cyclones.

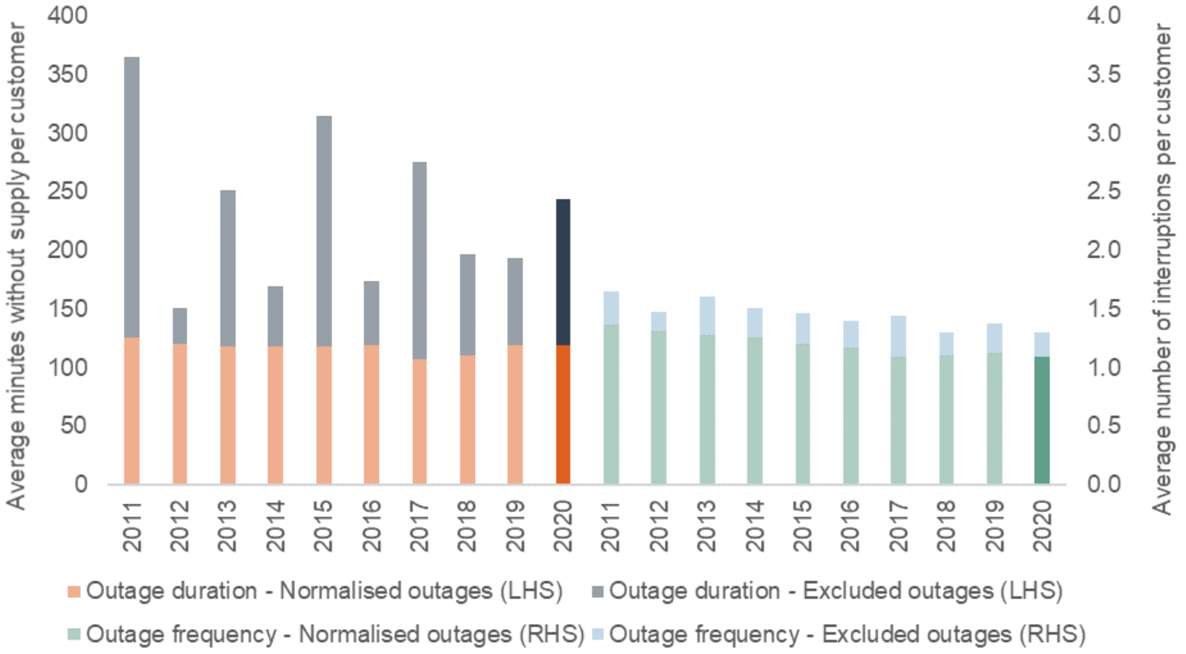
Together these allow us to evaluate the total frequency and duration of unplanned outages experienced by distribution network consumers—we refer to these as ‘total unplanned outages’. Considering these indicators together allows us to form a more comprehensive picture of unplanned outages experienced by consumers.

## SAIDI and SAIFI

In 2020:

- The average duration of normalised distribution outages increased slightly against 2019, however this varied between networks.
- The average duration of all unplanned outages increased by 25% against 2019, predominately driven by large increases in outage duration on New South Wales networks.
- Average normalised SAIFI declined on 2019. Customers in 2020 experienced fewer distribution network outages than at any time in our data series for both normalised and total unplanned outages.

**Figure 3-8 Unplanned outages – DNSPs**




Source: Operational performance data, Annual reporting RIN, AER analysis.

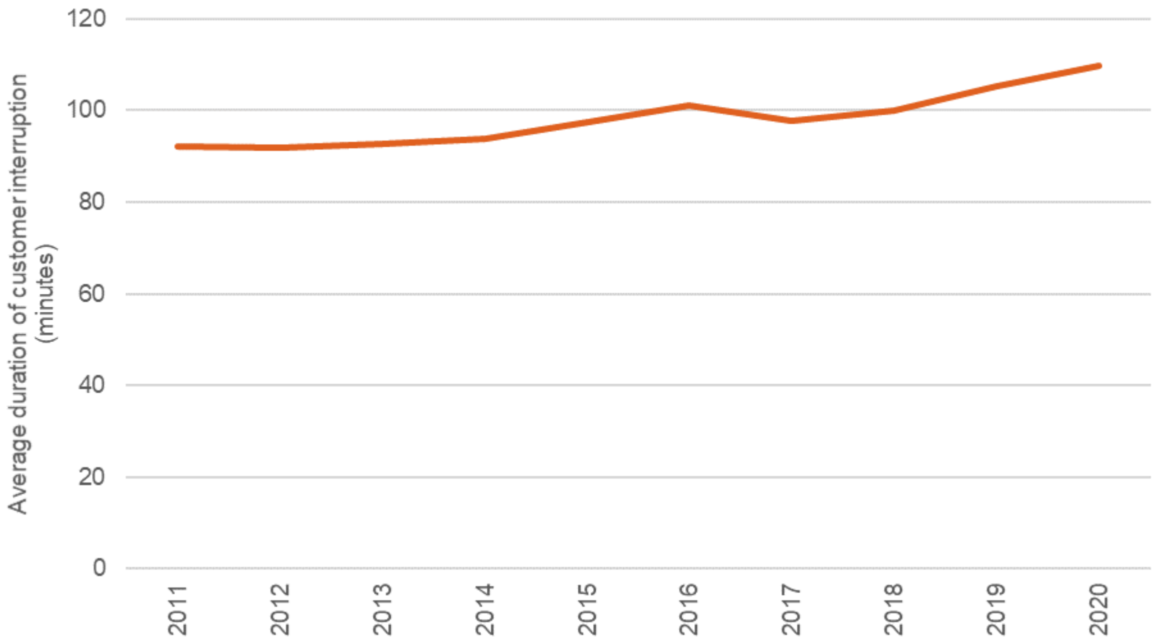
Over the longer time series, we observe that:

- Consumers have experienced fewer distribution network outages. This is driven by a clear trend of improvement in normalised SAIFI, which is in the control of the DNSPs. The improvement is evident even accounting for unplanned outages which are excluded from STPIS.
- In contrast, the average duration of outages (SAIDI) has been increasing since 2017 and approximately equal to levels observed in 2016. However, in some years there have been high-impact supply interruptions resulting in a material difference between normalised reliability and the duration of total unplanned outages.

Comparing the impact of excluded events on the frequency and duration of outages shows that we are excluding relatively few events, but these can have a substantial impact on the average duration of outages that consumers experience. This is consistent with the impact of major events, such as the Queensland floods; Victorian bushfires, the South Australian Black System Event and the summer 19/20 bushfires.

In 2020, normalised reliability continues a trend of greater reductions in frequency of interruptions compared to duration. In combination, the decline in SAIFI and increase in SAIDI describe a pattern of fewer outages that are longer on average.

**Figure 3-9 Relationship between normalised frequency and duration of interruptions – DNSPs**




Source: Operational performance data, AER analysis.

Networks are provided incentives under the STPIS to reduce normalised SAIDI and SAIFI. Historically these incentives have been set with roughly equal weight. This weighting appears to have contributed to a network preference for improvements in SAIFI over SAIDI. In 2018, we updated the STPIS incentive weights to 40% for SAIFI and 60% for SAIDI, which will reduce the apparent incentive for networks to prioritise improvements in SAIFI over SAIDI. Further detail on this is set out in our review of the STPIS[8].

The updated STPIS incentive weights will be applied to each network depending on the timing of their regulatory determination. In 2020 STPIS updates were applied to networks in New South Wales, ACT and Tasmania. Queensland and South Australian networks will have updates applied in 2021, with Victorian networks the following year. We will continue to monitor the relationship between frequency and duration of outages over time.

## Different reliability across feeder types

Presenting reliability as an average annual National Electricity Market (NEM) data series may over or understate the severity of reliability impacts on affected consumers. This is because consumers on different networks experience different levels of reliability, and, major events are often specific to a particular jurisdiction or network.

8 AER, Final decision— Amendment to the Service Target Performance Incentive Scheme (STPIS); Establishing a new Distribution Reliability Measures Guideline (DRMG), November 2018.

In last year's report, we illustrated how consumers on different networks experience different levels of reliability outcomes. Consumers can also experience different levels of reliability depending on where they are located within a network.

**What are the feeder types?**

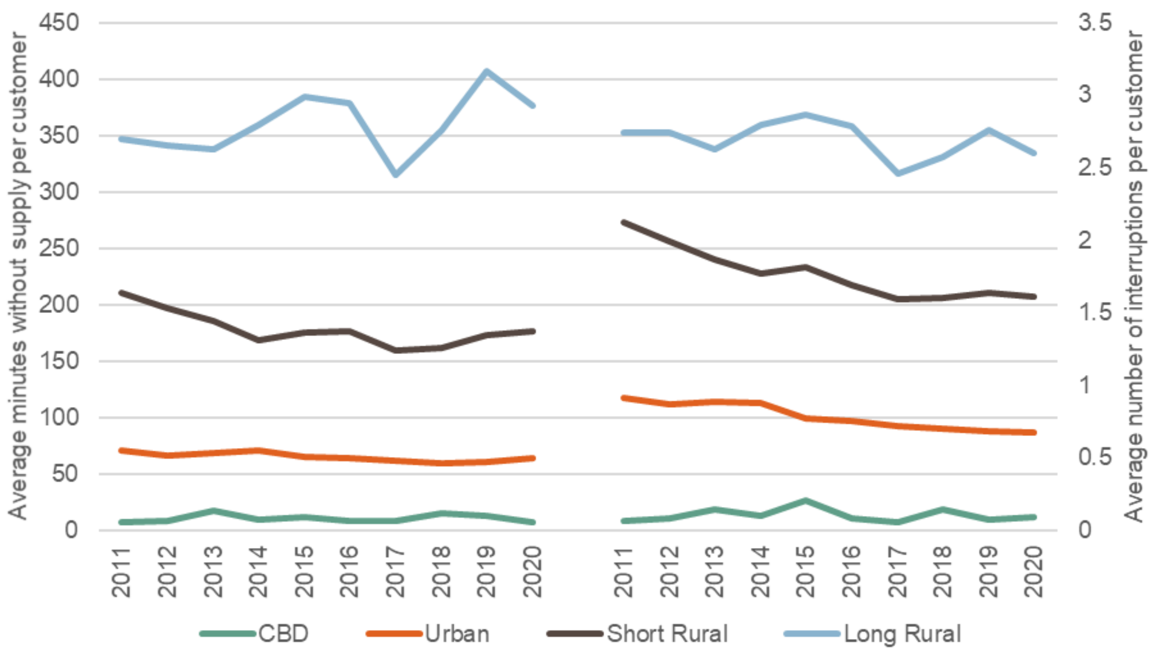
Customers are divided into four feeder types.

- CBD - a feeder in one or more geographic areas that have been determined by the relevant participating jurisdiction as supplying electricity to predominantly commercial, high-rise buildings, supplied by a predominantly underground distribution network containing significant interconnection and redundancy when compared to urban areas.
- Urban - a feeder which is not a CBD feeder and has a maximum demand over the feeder route length greater than 0.3 MVA/km.
- Rural short - a feeder with a total feeder route length less than 200km, which is not a CBD or urban feeder.
- Rural long - a feeder with a total feeder route length greater than 200km, which is not a CBD or urban feeder.

Figure 3-9 shows that on average, consumers on rural feeders experience longer and more frequent normalised interruptions than CBD or urban consumers. This is likely driven by a number of factors including:

- different network topology
- higher redundancy capital costs per consumer on longer feeder types
- increased response time relative to line length

**Figure 3-10 Different levels of normalised reliability by feeder type - DNSPs**



Source: Operational performance data, AER analysis.

Figure 3-9 also shows that consumers have experienced different trends in reliability over time.

- CBD consumers have experienced proportionately high variability in reliability. However, this largely reflects a low 'baseline' level of outages. Consumers on CBD networks experience fewer outages than consumers on any other feeder type.
- Urban and short rural consumers have experienced improvements in the duration and frequency of outages.
- Long rural consumers have experienced a small improvement in the frequency of outages, but variable and worsening duration of interruptions.

Presenting these findings in an annual NEM-average data series may understate the severity of reliability impacts on affected consumers noting that consumers on different networks experience different levels of reliability, and, major events are often specific to a particular jurisdiction or network.

For this reason it is our intention to more comprehensively explore reliability outcomes throughout the NEM. In chapter 5, we have examined seasonal reliability across the NEM and how this can impact networks differently.

## 3.5 Distribution network utilisation

Network utilisation measures the extent to which a network's assets are being used to meet maximum demand.[9]

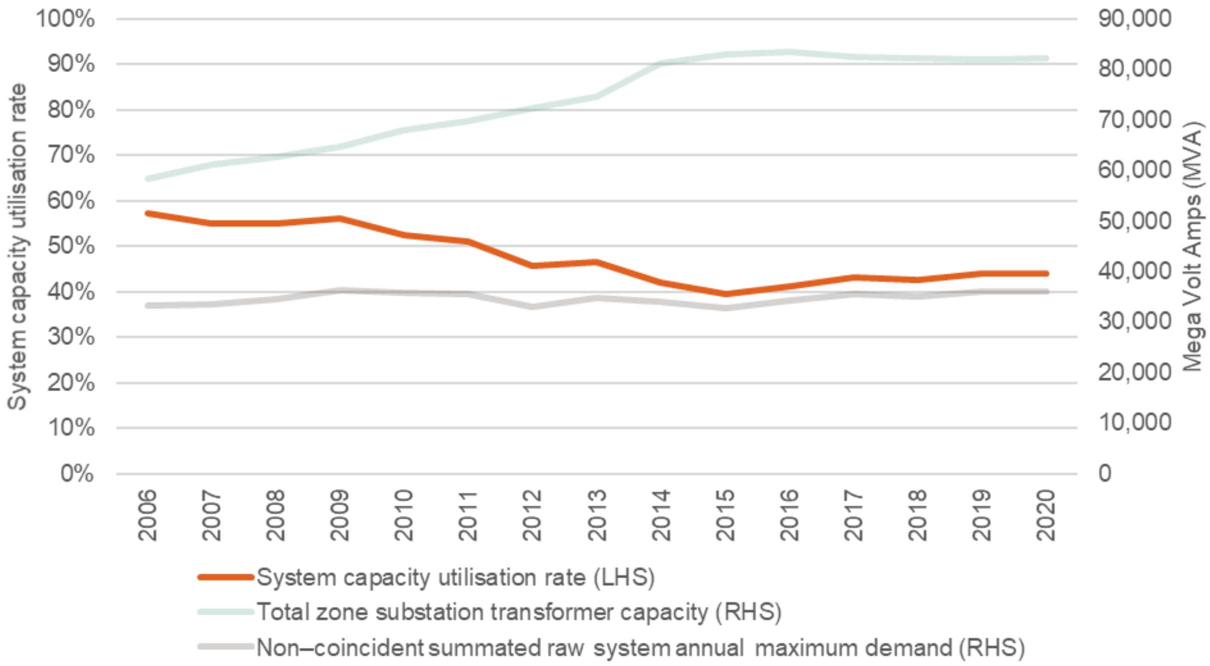
In our view, it is an informative but incomplete measure of the network assets' preparedness to respond to short-term changes in demand. We consider this an important service output consumers can expect for funding investment in the networks. However, we recognise that it is an aggregated network-wide measure, which can mask localised issues.

In 2020:

- Average distribution network utilisation was unchanged from 2019. This follows on from a medium term trend of increasing utilisation following the period of major capacity expansion from 2006 to 2014.

9 For DNSPs we measure network utilisation as the ratio of reported level of non-coincident maximum demand (MVA) to total zone substation transformer capacity (MVA).

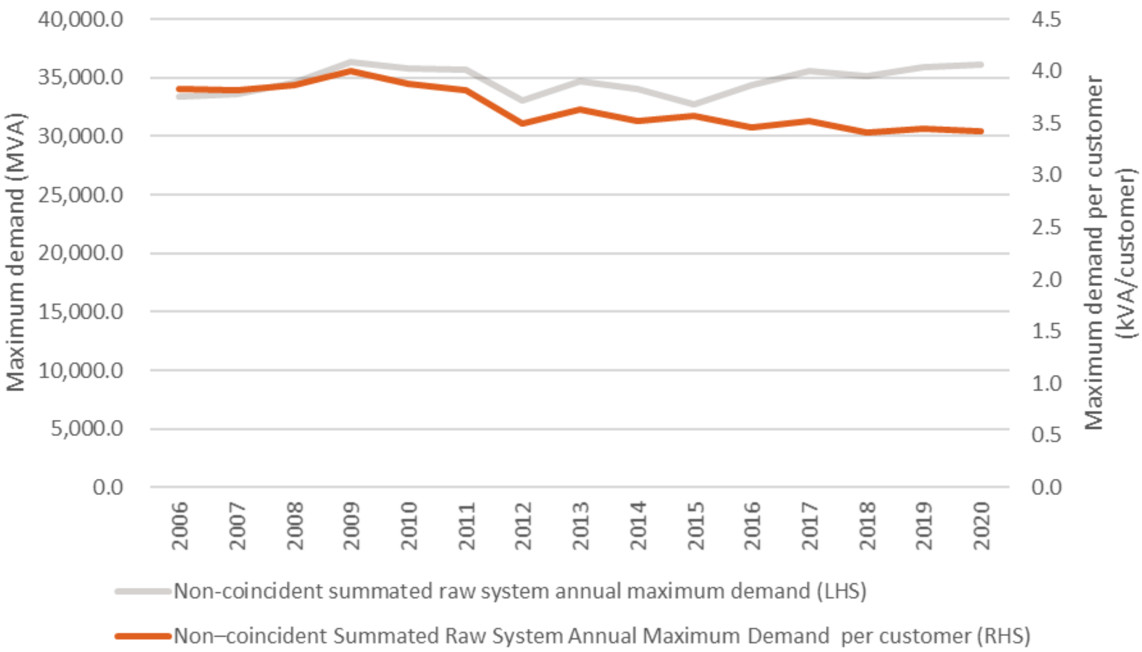
## Figure 3-11 Distribution network utilisation – Total DNSPs




Source: Operational performance data, AER analysis.

In future years' reporting, we are intending to expand on this measure to investigate the changing dynamics of per-customer demand. To illustrate, Figure 3-11 below compares the measure of maximum demand used in our calculation of utilisation against its per-customer equivalent. It shows that while maximum demand in 2020 is roughly consistent with levels in 2009, per customer demand has declined materially over the same period. In our view, further analysis could yield insights about the impacts of distributed energy resources and energy efficiency measures on use of the networks.

## Figure 3-12 Changes in maximum demand per customer




Source: Operational performance data, AER analysis.

## 3.6 Network profitability

Alongside trends in network expenditure and the resulting service outputs, we consider indicators of profit that networks have been able to generate from the revenue allowances paid by consumers.

The regulatory framework is designed to compensate networks in expectation for efficiently incurred costs (such as operating expenditure, depreciation, interest on debt and tax) and to provide them with an expected profit margin in line with the required return in the market for an investment of similar risk. The expected profit margin, if set at an appropriate level and supported by appropriate incentives, should attract efficient investment.

As a feature of the incentive-based regulatory framework, we expect networks' actual outcomes to differ from the forecasts and benchmarks we set. The revenue requirement is not a guaranteed return, as the networks' actual returns are determined in part by whether they spend more or less than the forecasts and benchmarks used to determine their revenue allowances. Nonetheless, to the extent that profitability results are systematically and materially higher or lower than forecast, this would prompt us to investigate the causes in more detail.

**Forecast returns on capital**

The return on capital building block included in our revenue determinations is made up of a return on debt component and a return on equity component. The return on debt, for example, is made up of the amount of debt we forecast (RAB x gearing) multiplied by the rate of return on debt. Equity is similar. We refer to the rates of returns on debt and equity (in combination the weighted average cost of capital) as 'forecast' returns.

### Returns on assets

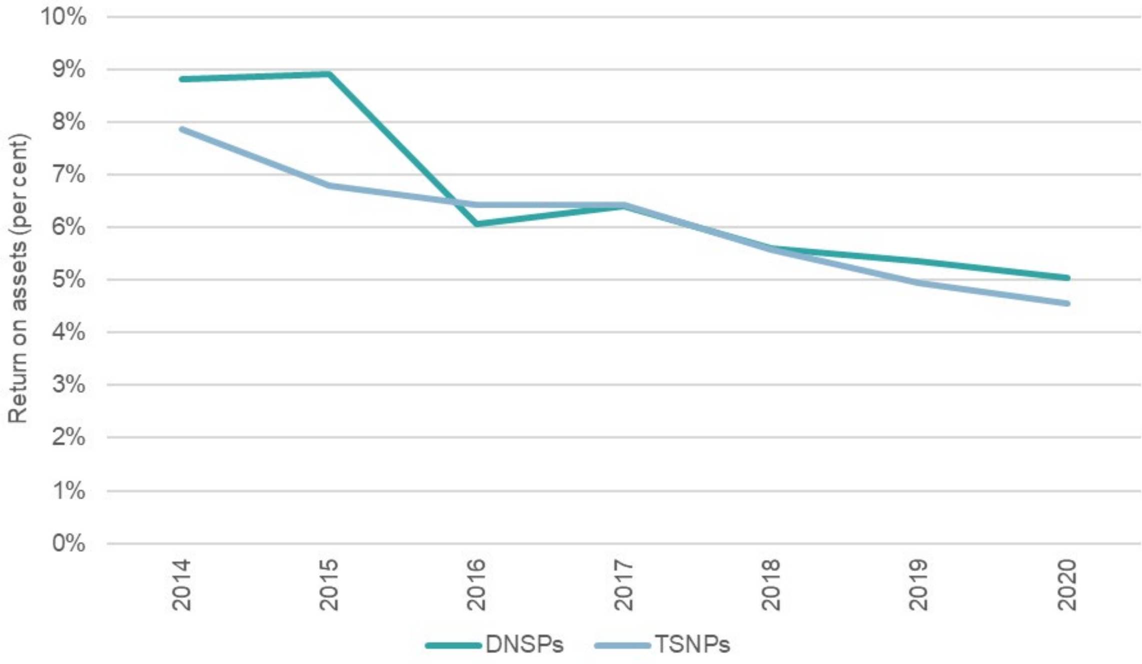
The return on assets is a simple, partial profitability measure allowing us to compare network profits against our allowed rate of returns. It does not capture all potential drivers of network profit—in particular, it does not capture network performance against our allowances for the costs of debt (interest expense) or tax expense. However, it does capture the impact of incentive scheme rewards and penalties as well as network performance against operating expenditure allowances.

In 2020:

- Average network returns on assets continued to decline; however
  - Networks continued to earn real returns on assets roughly 1% above forecast—that is, an average real return on assets of 4.9% compared to a forecast of 3.8%
  - The pattern in actual outcomes is largely consistent between DNSPs and TNSPs

The decline in the average for 2020 is exaggerated by the introduction of Northern Territory Power and Water Corporation. 2020 was the first year in which NT PWC's revenue was set under an AER decision, and it is therefore not included in the 2014-19 averages. NT PWC's forecast and actual returns on assets are both relatively low due largely to having both of its rates of return on debt and equity reset in a low interest rate environment.

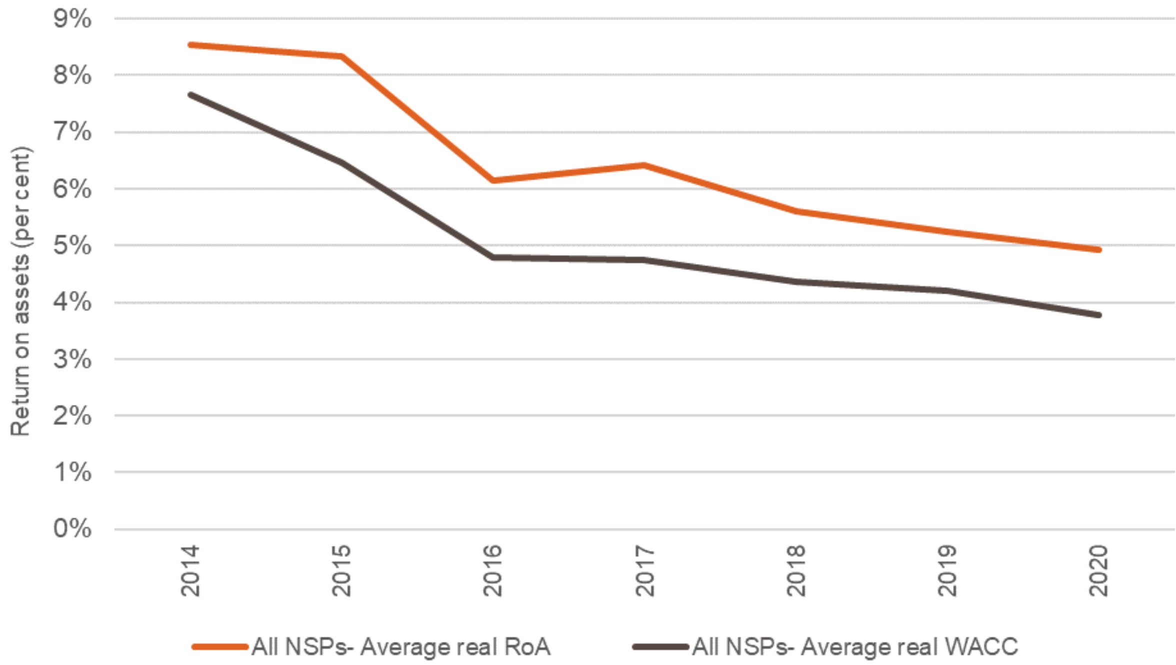
**Figure 3-11 Real returns on assets– DNSPs and TNSPs**




Source: Financial performance data, AER analysis.

Networks have continued to generate real returns on assets which exceed forecast returns despite declining forecast returns.

**Figure 3-12 Real returns on assets compared to forecast real WACC**




Source: Financial performance data, AER analysis.

We encourage stakeholders to review return on asset outcomes alongside our analysis of networks' returns on regulated equity, set out in section 6. Compared to that measure, the return on assets is less comprehensive but simpler to calculate and interpret. In combination, we consider they best equip stakeholders to form views on how network profits compare against the forecast returns on capital included in our revenue forecasts.

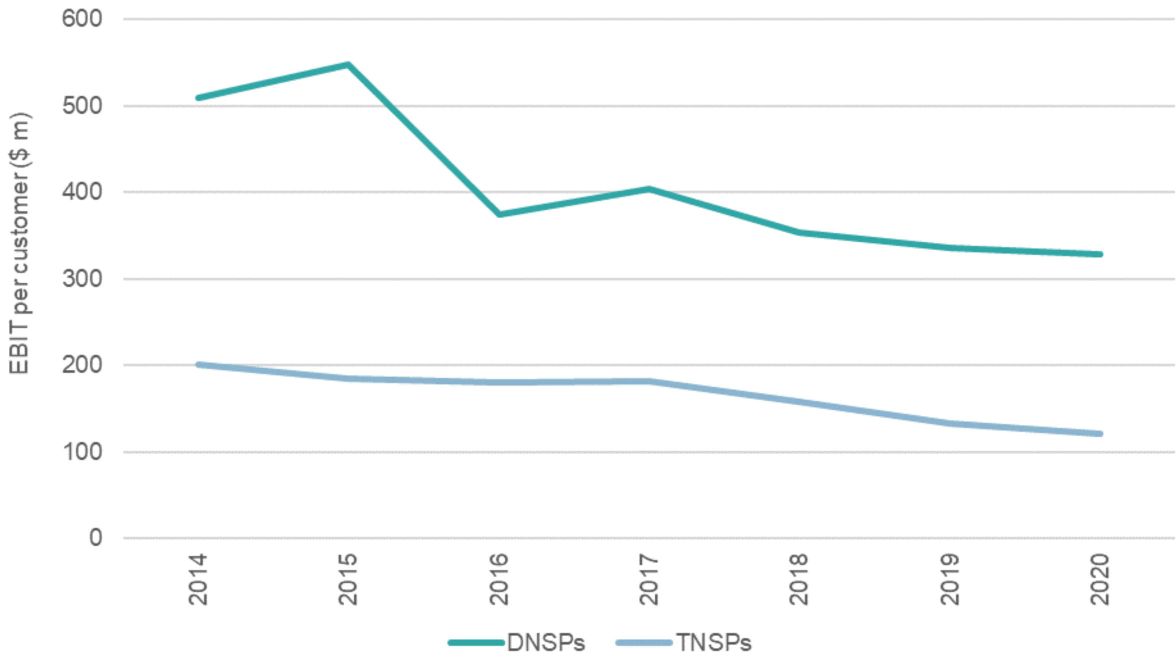
## EBIT per consumer

EBIT per consumer is a measure of the operating profit of a networks over its consumer base. It is a complementary measure to the return on assets, capturing the same measure of profit (earnings before interest and tax, or EBIT) over a different cost-driver.

Importantly, EBIT per consumer is *not* a measure of the profit that individual residential consumers contribute to the network. It is an average of all consumers, including SMEs and large consumers who contribute a substantially greater proportion of network revenue per consumer despite their smaller numbers.

Figure 3-12 sets out the average real EBITs per consumer, including incentive scheme payments and excluding the impacts of RAB indexation. In our view, this is the most informative single version of the EBIT per consumer measure. It uses an estimate of EBIT that is consistent with how it is calculated in estimation of the real returns on assets.

**Figure 3-13 Average EBIT per consumer – Including incentive scheme payments and excluding RAB indexation**




Source: Financial performance data, AER analysis

Over the 2014 to 2020 period, we observe that:

- The EBIT per consumer declined across most DNSPs.
- EBIT per consumer has also converged between the DNSPs. In 2014 the range of EBIT per consumer was $855, whereas in 2019 the range was $511.[10]
- We would expect both of these trends to continue as allowed returns on capital are reset under the 2018 binding rate of return instrument.

Our estimates of EBIT per consumer for TNSPs are materially lower than for DNSPs. This is a consequence of the relatively higher capital intensiveness of distribution networks compared to transmission networks—that is, distribution networks typically have larger RABs per customer. However, it does not mean that TNSPs are less profitable than DNSPs for the same levels of investment.

## RAB multiples

RAB multiples are a measure of investor expectations about a network's future returns and are widely used by market analysts in connection with regulated utilities. They are forward-looking, where the other profitability measures are based on historical outcomes. However, most of our regulatory approaches are predictable and set out in guidelines. As a result, in an environment where returns had been systematically insufficient, we expect that this might be evident in RAB multiples.

10 Excluding Ergon Energy from the sample of DNSP earnings per customer the range was $569 in 2014, compared to $216 in 2019.

In practice there are a number of factors which impact RAB multiples and not all of those factors are directly outcomes of the regulatory regime or the networks' core regulated services. In advice given during development of the 2018 rate of return instrument, Biggar observed that:[11]

> *Based on the data above and the analysis in this paper, is it possible to suggest a "normal" or "typical" range for RAB multiples?*
>
> *This is difficult to assess and there is no fully objective perspective. In my view, due to each firm's ability to earn rewards for taking desirable actions, an Enterprise Value (EV)/RAB ratio of slightly above one should be considered normal. This is consistent with the theoretical observation that the regulated firm must be left some "information rents" in an optimal regulatory contract. I therefore suggest that, as a starting point, an EV/RAB in the vicinity of 1.1 should be considered unobjectionable. In addition, due to uncertainties and complexities in the regulatory process, and in the process of estimating the EV and the RAB, I suggest an error margin of plus or minus twenty per cent on this figure could be considered a "normal range".*

For these reasons, we do not expect RAB multiples to be precisely at 1 under a well-functioning regulatory regime, and consider that RAB multiples somewhat above 1 would not necessarily indicate a problem.

This is consistent with the approach followed by a range of other regulators that use RAB multiples as a reasonableness check or input into allowed rates of return.

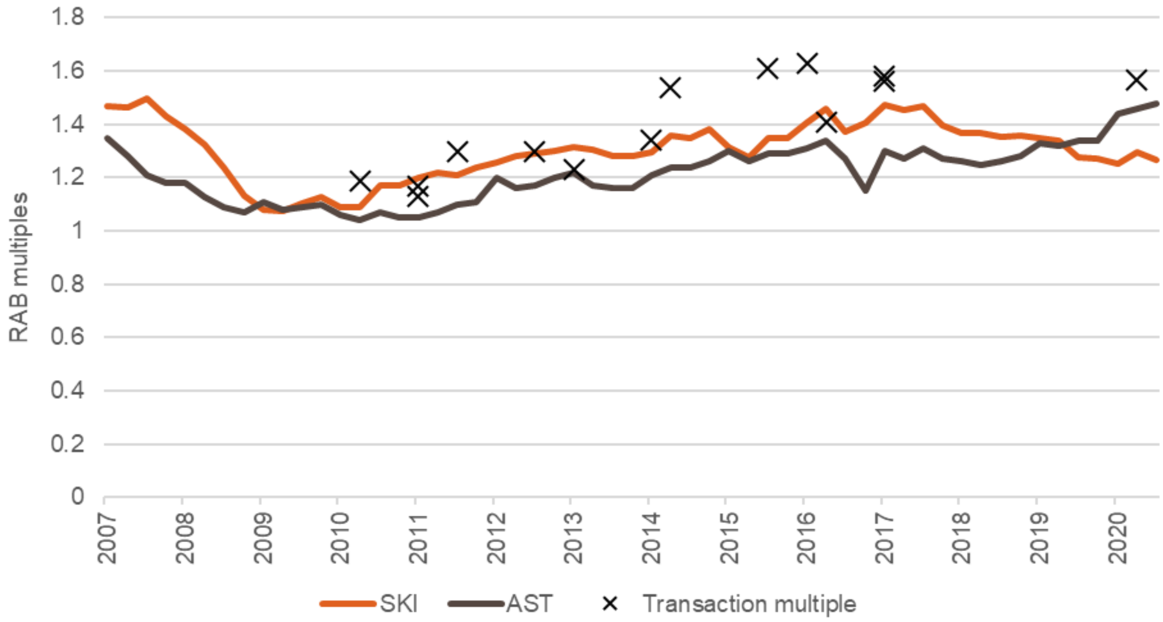
To draw on the largest possible body of market evidence, we have reported on two types of RAB multiples, sourced from Morgan Stanley:

- Transaction multiples - RAB multiples arising from the transaction of a discrete component of an ownership group including regulated networks.
- Trading multiples - RAB multiples generated using market value data on the enterprise value of publicly listed entities.

Figure 3-13 combines our time series of both trading and transaction RAB multiples.

11 Darryl Biggar, Understanding the role of RAB multiples in the regulatory process, 2018. Available here.

**Figure 3-14 AER regulated networks – transaction and trading multiples**




Source: Morgan Stanley Research, AER analysis.

Note: SKI is Spark Infrastructure, which holds ownership stakes in SA Power Networks (49%), Victoria Power Networks (49%) and TransGrid (15%). AST is AusNet Services, which owns a Victorian electricity distribution network, electricity transmission network and gas distribution network.

Recognising that the drivers of RAB multiples are difficult to quantify precisely, we remain of the view that the evidence on RAB multiples in combination with the other analysis in this report supports a view that investors view regulated returns as being at least sufficient to attract investment. Put conversely, it would be difficult to explain the persistence of premiums in both trading and transaction multiples if investors perceived systematic deficiencies in returns generated through the economic regulatory framework.

In new data available since the last report, we note that:

- In July 2020, OMERS acquired a 19.99% stake in TransGrid at a RAB multiple of 1.57. This is approximately the same RAB multiple at which the privatisation of TransGrid took place at in 2014.
- The average of trading multiples is slightly up on 2019.

As with all transaction multiples, we expect the premium on the TransGrid transaction may to some extent reflect asset or buyer specific factors. However, in our view the stable premium for the specific asset still suggests projected returns under the framework are at least sufficient to attract investment, noting:

- A significant upcoming transmission investment program, including Project Energy Connect.
- Forecast rates of return have declined since the initial privatisation of TransGrid.

- Trading multiples have varied through time but, since 2014, have been relatively steady despite material declines in allowed returns on capital over the same period.

Similarly, we observe variation in trading multiples over time between AST (AusNet Services Ltd) and SKI (Spark Infrastructure Group). This variation suggests that there are some company-specific factors which impact trading multiples. However, it remains the case that even the lower of the two multiples over time has traded consistently at a premium to the RAB.

# 4 Impact of COVID-19 on network revenue and returns

To reduce the spread of the COVID-19 virus in March and April 2020, state[12] and federal[13] governments introduced a number of lockdown restrictions. This led to schools, workplaces and businesses closing and widespread changes to Australians' day-to-day activities. These changing activities also had an effect on the energy needs and consumptions of residential, commercial and industrial consumers.

For most of Australia, June and July 2020 ushered in a 'new normal' where restrictions were loosened and businesses and schools reopened. However, in Victoria, a second wave of the COVID-19 virus led to the state reintroducing lockdown measures,[14] with greater restrictions imposed in Melbourne to curtail the spread of the virus.[15]

In this section, we set out our analysis of the impact arising from the COVID-19 pandemic on the electricity network service providers and their consumers. In particular, we have focussed on:

- How COVID-19 has impacted the consumption of residential, small and medium enterprise (SME) and large consumers.
- As a result, how COVID-19 has impacted networks' revenue collection and how this will impact forecast revenues in future regulatory years.

We have focussed on the impacts in Victoria particularly because:

- The first and second wave of COVID-19 lockdowns and resulting effects were longest lasting in Victoria, and fit entirely within the 2020 Victorian reporting period (January-December). In contrast, the 2020 reporting period for other DNSPs (July 2019-June 2020) captures only the earlier months of the pandemic's impact.
- Likely as a consequence of the above, annual consumption data amongst the other DNSPs suggests relatively less impact in the 2020 regulatory year.[16]
- In Victoria, we are able to observe a more detailed picture of these impacts owing to the high penetration of smart meters,[17] allowing a relatively comprehensive weekly picture of electricity consumption. The Victorian DNSPs collectively provided to us weekly aggregate consumption information by consumer type (residential, SME and large business) over 2020 and we have relied on this data in our analysis.

12 New South Wales Government, *New COVID-19 restrictions begin as schools move towards online learning*, 23 March 2020; Queensland Government, *Business closures and restrictions*, 23 March 2020; South Australian Government, *Service SA changes to stop the spread*, 27 March 2020; Tasmanian Government, *Keeping Tasmanians safe and secure*, 1 April 2020; Victorian Government, *Statement from the Premier*, 30 March 2020; Western Australian Government, *Important new COVID-19 measures come into effect*, 23 March 2020.

13 Department of Prime Minister and Cabinet, *National Cabinet Statement – Media Statement*, 29 March 2020.

14 Department of Premier and Cabinet, *Statement from the Premier*, 7 July 2020.

15 Department of Premier and Cabinet, *Statement on Changes to Melbourne's restrictions*, 2 August 2020.

16 This data for each DNSP for the 2020 regulatory year is available in tab 7 – Energy Delivered of the Electricity DNSP – Operational Performance Data.

17 Smart meters (also known as an advanced meter or 'type 4' meter) is a device that digitally measures your energy use. A smart meter measures when and how much electricity is used at your premises. It sends this information back to your energy retailer remotely, without your meter needing to be manually read by a meter reader.

Our key findings are that:

- Overall, the COVID-19 response appears to have had limited aggregate impact on the revenue, expenditures and allowed returns of NSPs and in particular DNSPs.
- Over 2020 in Victoria, we observed a material shift from small and medium enterprise (SME) consumption to residential consumption.
- This is important as consumption charges remain the major source of network revenue in Victoria and in the NEM more generally.

For most of the Victorian DNSPs this shift resulted in limited overall impact on consumption or revenue. However, a greater proportion of CitiPower's revenue depends on CBD SME consumption, resulting in a material under-recovery of revenue which will be recovered gradually over the 2021-26 regulatory period.[18]

In addition to direct revenue impacts on networks via changes in usage, networks were involved through 2020 in two mechanisms under which they could provide support to retailers who at that time were operating under our statement of expectations.[19] However, there was limited uptake of the ENA voluntary relief package and the AEMC rule change mechanism to defer revenue, which decreased the potential cash flow impacts on networks.

Importantly, we recognise that the impacts of COVID-19 are ongoing and that many states and territories have during 2021 experienced periods of lockdown, some prolonged. We will continue to monitor these effects as necessary in coming years. In the remainder of this section, our analysis is focussed on impacts of the COVID-19 pandemic on network revenue collection over regulatory year 2020.

## 4.1 Impacts of COVID-19 on Victorian electricity consumption

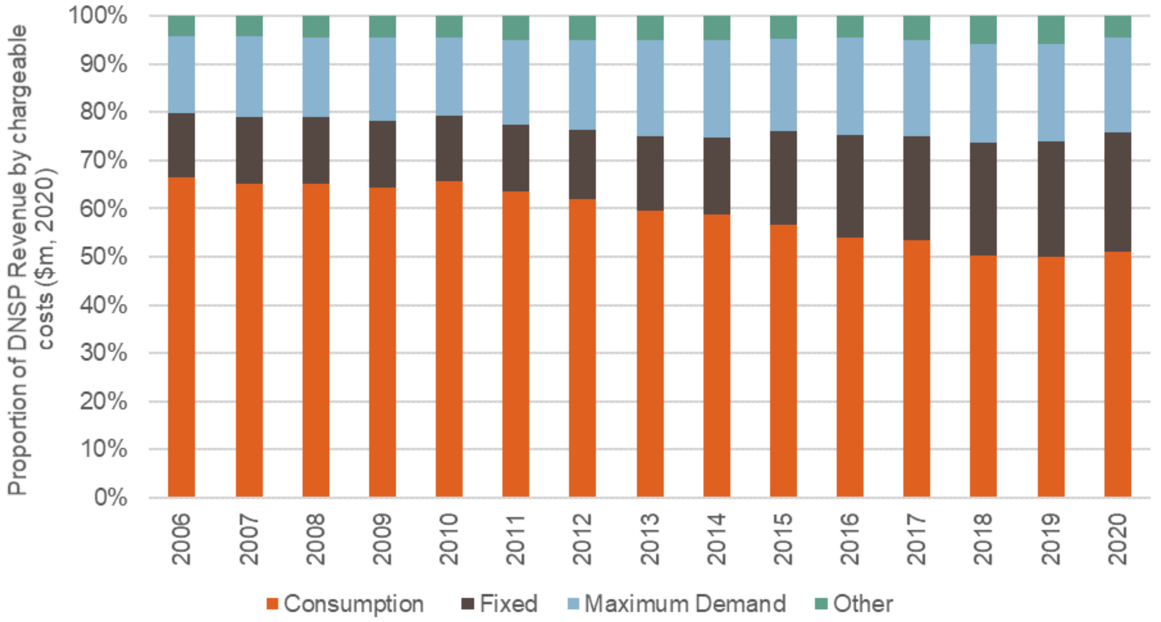
To explore the impact of COVID-19 on network consumers, we have focussed in particular on observable changes in consumption patterns.

These changes in consumption patterns are material for both networks and their consumers because, as set out in Figure 4-1, consumption charges remain the most significant source of network revenue and hence network costs faced by consumers.

18 AER, *Final decision - CitiPower distribution determination 2021–26 - Attachment 14 - Control mechanisms*, 2021, pp 16-18.

19 https://www.aer.gov.au/publications/corporate-documents/aer-statement-of-expectations-of-energy-businesses-protecting-customers-and-the-energy-market-during-covid-19

**Figure 4-1 Composition of DNSP revenue by chargeable cost - Whole of NEM**



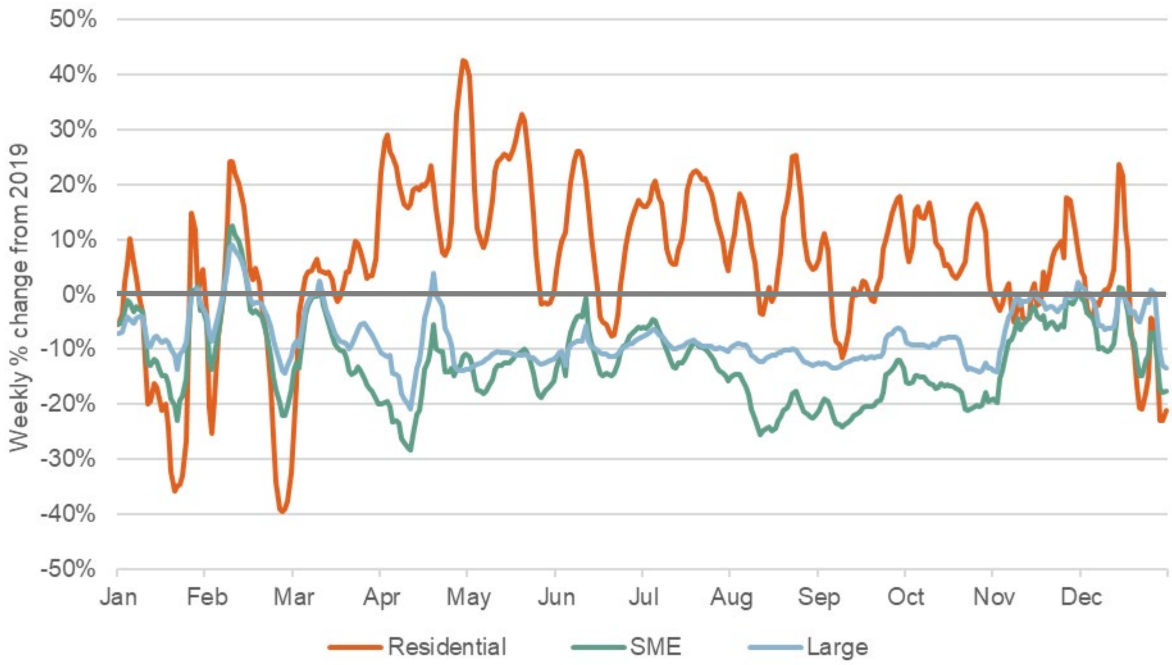

Note: For this chart:

- ‘consumption’ charges includes: revenue from energy delivery charges where time of use is not a determinant, revenue from on–peak energy delivery charges, revenue from off–peak energy delivery charges and revenue from shoulder period energy delivery charges.
- ‘fixed’ charges includes: revenue from fixed consumer charges.
- ‘maximum demand’ includes: revenue from contracted maximum demand charges and revenue from measured maximum demand charges
- ‘other’ includes: revenue from controlled load consumer charges, revenue from unmetered supplies and revenue from other sources.

Source: DNSP Economic benchmarking RINs, AER analysis.

To illustrate the impact of COVID-19 on electricity consumption patterns, Figure 4-2 shows the Victorian weekly average percentage change in consumption by consumer type across the 2020 regulatory year.

**Figure 4-2 Victorian weekly average change in consumption from 2019**




Source: Victorian DNSP monthly energy consumption report, AER Analysis

In our view, this illustrates that:

- Up to the lockdowns in March, consumption by all consumer types was highly correlated with 2019. Variation above and below 2019 consumption appears to be driven mainly by temperatures and the timing of public holidays.20
- Following the introduction of lockdowns in March, residential consumption increased to materially higher levels against 2019, while SME and large consumer consumption declined to materially lower levels against 2019.
- In particular, it also shows the greater impact that the second wave had on SME business, especially when stage 4 restrictions were introduced at the start of August.21
- At the conclusion of lockdowns in November 2020, consumption by consumer types returned to being highly correlated.

Recognising the close relationship between these changes and timing in lockdown, we have reached the view that the broad shift in consumption from business to residential consumers is directly attributable to the impact of COVID-19 as business activity declined or stopped and many Victorians were consuming most or all of their electricity at home.

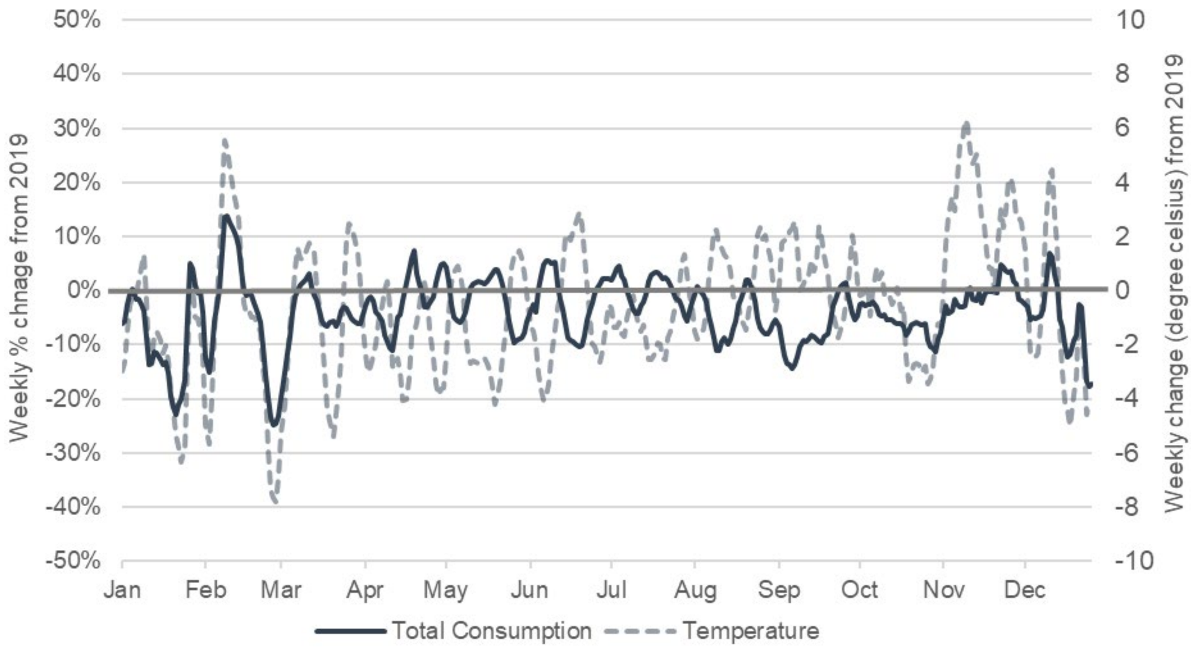
20 The timing of public holidays i.e. when in March or April the Easter public holidays occur, the date of the AFL Grand Final or if the public holiday occurs on a weekend can significantly influence the weekly consumption. This is due to public holidays having decreased daily consumption.

21 https://www.dhhs.vic.gov.au/updates/coronavirus-covid-19/premiers-statement-changes-melbournes-restrictions-2-august-2020

## Impacts of temperature on consumption

Aside from the broad shift in consumption from businesses to residential consumers, there remains material week-to-week variation in 2020 consumption compared to 2019. In our view, this largely reflects the sensitivity in consumption of electricity to temperature. We have illustrated this relationship in Figure 4-3, which compares the weekly average change in overall Victorian consumption against the weekly difference in temperature in 2020 compared to 2019.

**Figure 4-3 Victorian weekly average change in consumption and degree Celsius from 2019**




Source: Victorian DNSP monthly energy consumption report, AER Analysis

As we would expect:

- Consumption increases alongside higher temperatures in the summer months as consumers use more cooling appliances; and
- Consumption increases alongside lower temperatures in the winter months as consumers use more heating appliances

So, when comparing 2020 consumption against 2019 consumption, we observe two distinct effects:

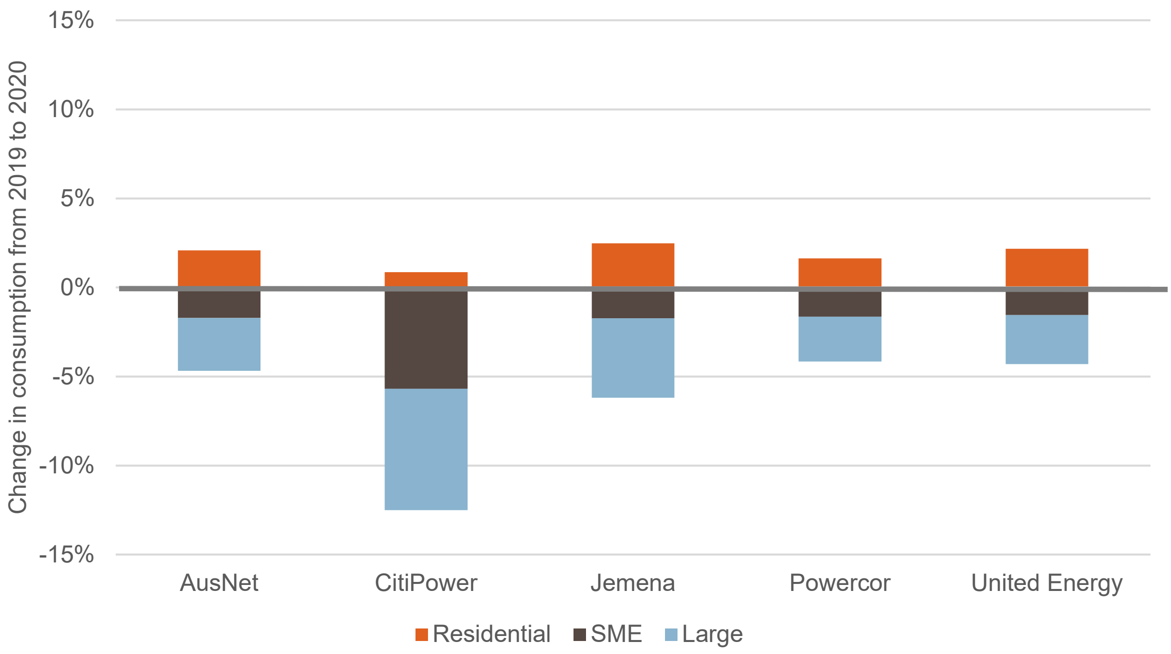
- Lockdowns implemented during COVID-19 led to a shifting 'baseline' of consumption through the period of lockdowns; and
- Week to week variation around that baseline was driven by warmer or cooler weeks compared to the corresponding week in 2019

## 4.2 Differences between individual Victorian distribution networks

Within these overall impacts across the Victorian DNSPs, we observe similar patterns but different levels of acuteness between the networks. In our view, this variation reflects the differences between the networks and their consumer bases. In the next section, we explore the different impacts between Victorian networks, and the drivers for these differences.

Victorian electricity consumers are served by five DNSPs; AusNet, CitiPower, Jemena, Powercor and United Energy.

**Figure 4-4 Change in 2020 consumption from 2019 for Victorian DNSPs—Contribution to overall consumption impact**



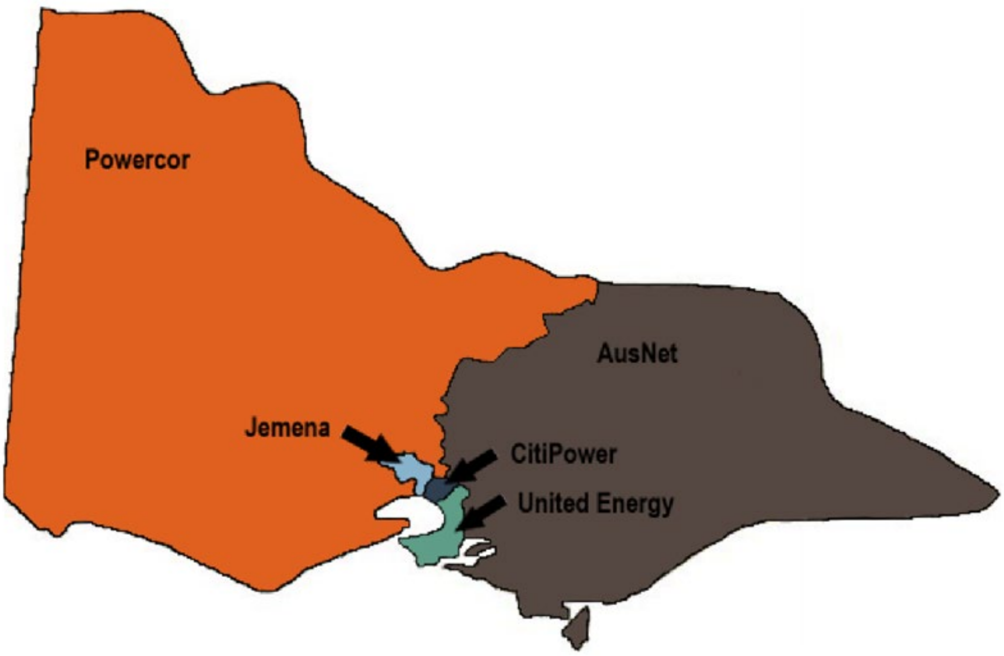

Source: Victorian DNSP monthly energy consumption report, AER Analysis

Figure 4-4 illustrates that:

- Across all DNSPs, there was a broadly similar pattern of lower business (SME and large consumer) consumption and higher residential consumption
- For most DNSPs, those impacts roughly offset, leading to overall consumption declines of between 2 to 4%
- However, CitiPower experienced larger declines in business consumption and smaller growth in residential consumption, resulting in a more material (11%) overall reduction in consumption

In our view, these patterns of impact can largely be explained by the different geographical setting for the DNSPs and, as a result, their exposure to different consumer types. To illustrate these differences, Figure 4.5 shows the approximate service areas of each network.

**Figure 4.5 Location of Victorian electricity DNSPs**



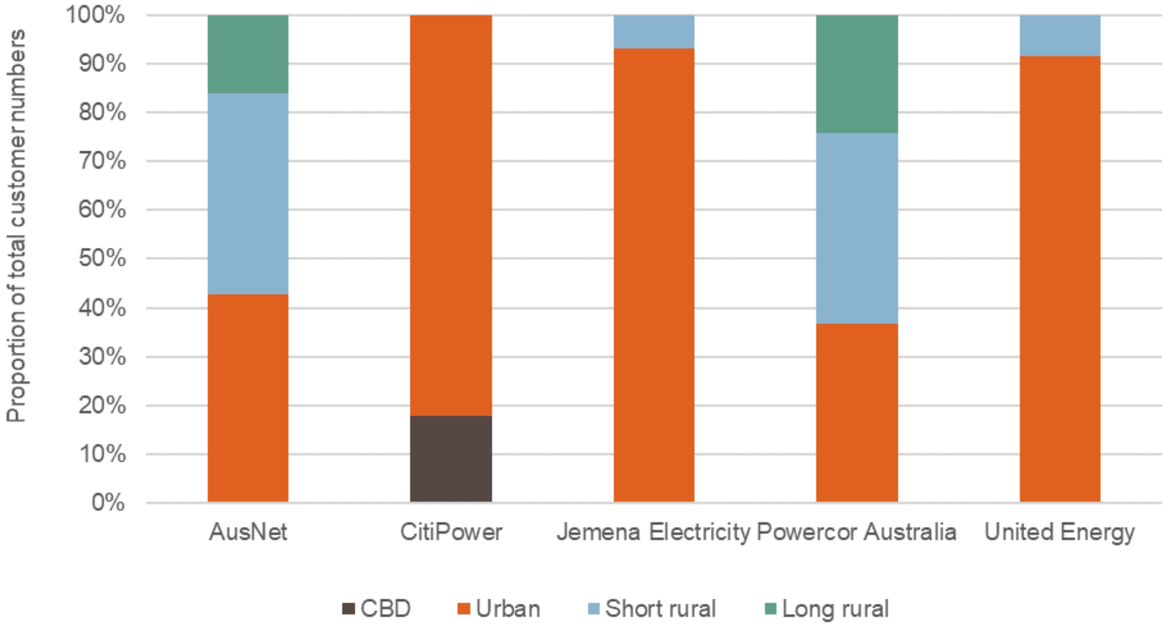

Source: AER Analysis

This highlights that:

- Powercor and AusNet cover substantially larger, more rural areas
- Jemena, CitiPower and United Energy cover smaller and denser consumer bases in Melbourne and surrounding areas

Reflecting these different areas, Figure 4-5 shows the material differences between DNSP consumer compositions.

**Figure 4-5 Composition of Victorian DNSP consumer by feeder type**[22]




Source: DNSP Economic benchmarking RINs, AER analysis.

In particular, we observe that:

- Powercor and AusNet predominantly serve rural and regional consumers
- United Energy largely serves urban consumers, and a small number of regional consumers. Jemena also serves urban consumer, a small number of regional consumers and the Tullamarine Airport
- CitiPower exclusively serves CBD and urban consumers

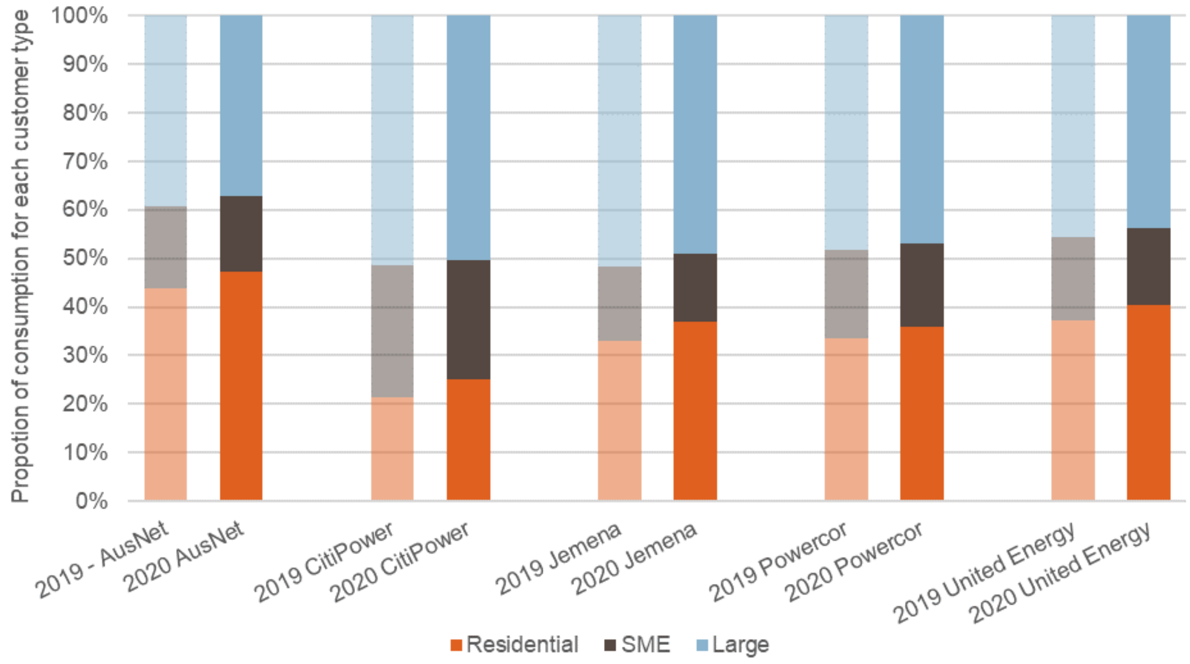
## 4.3 Investigating the material impacts on CitiPower

While COVID-19 appears to have had a broadly similar pattern of impact between the DNSPs, the overall impact is most acute for CitiPower. In particular, it appears to be driven by distinctively severe impacts of the lockdowns on CBD based businesses—both large and small.

Figure 4-6 shows the proportionate consumption for each consumer type, which shows that in ordinary circumstances, the highest proportion of CitiPower's consumption depends on business consumption and the lowest on residential consumption.

22 The feeder types are defined in section 3.

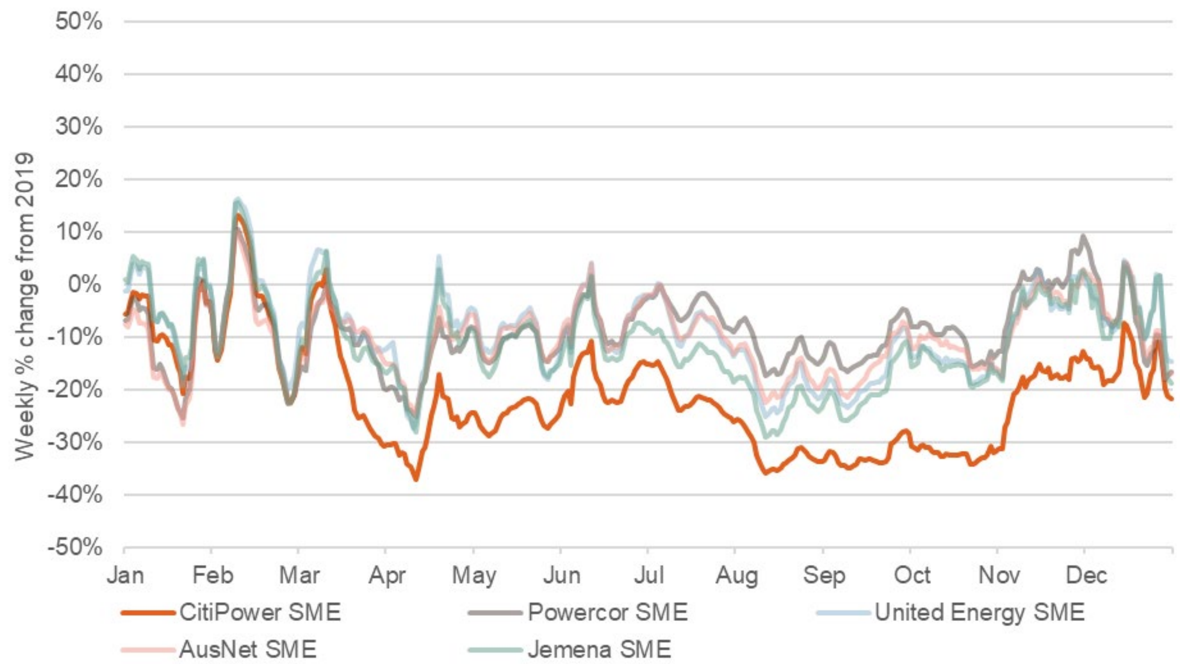
### Figure 4-6 Composition of Victorian DNSP consumption by consumer type




Source: Victorian DNSP monthly energy consumption report, AER Analysis

Figure 4-7, below, highlights that while SME consumption during lockdowns declined materially amongst most DNSPs, it was most acute for CitiPower.

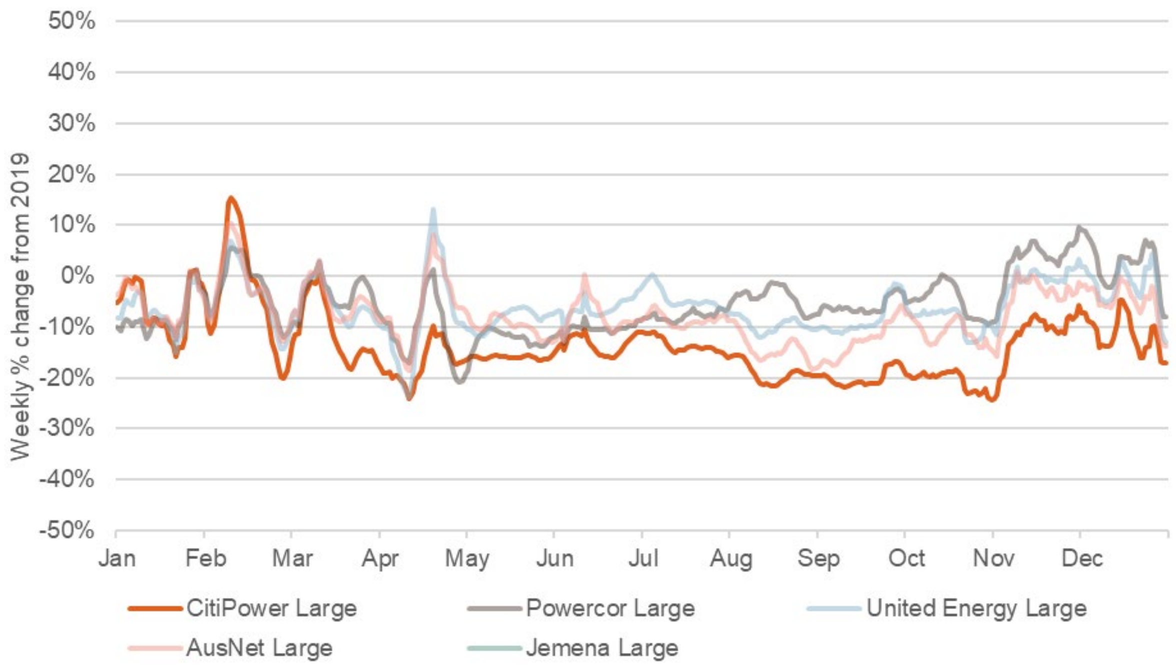
### Figure 4-7 Victorian weekly average change in SME consumption from 2019




Source: Victorian DNSP monthly energy consumption report, AER Analysis

Similarly, Figure 4-8 shows the same comparison for large consumers.

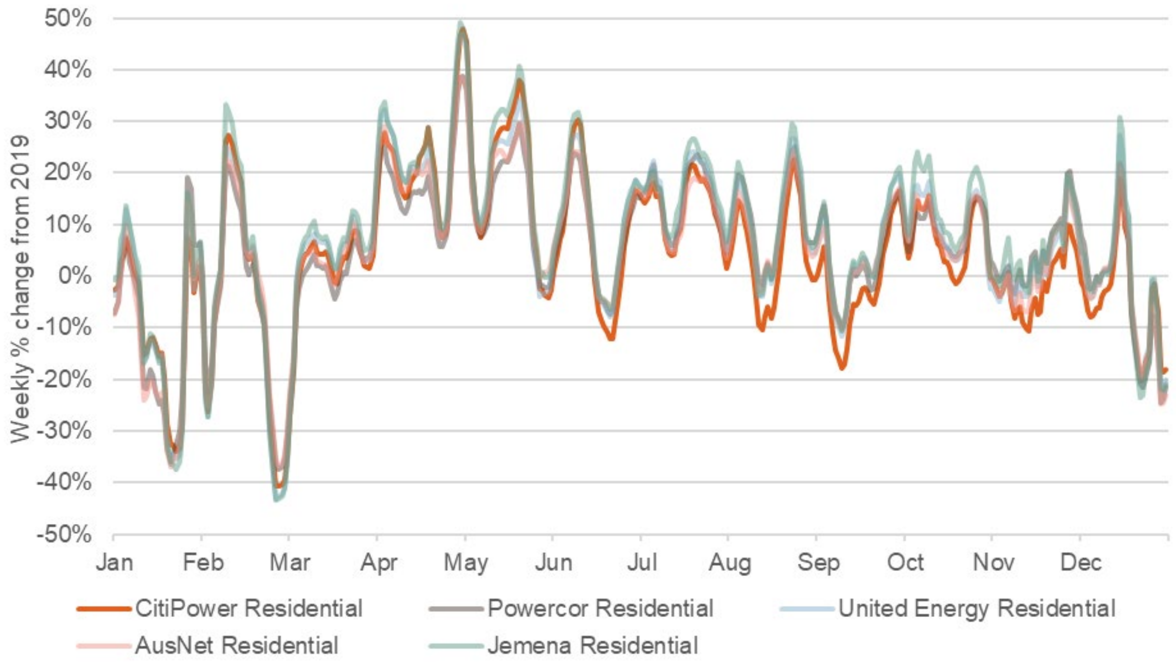
**Figure 4-8 Victorian weekly average change in large consumption from 2019**




Source: Victorian DNSP monthly energy consumption report, AER Analysis

In contrast, Figure 4.9 compares the weekly average change in consumption for residential consumers. This shows that the changes in residential consumption for 2020 were consistent across the DNSPs.

**Figure 4-9 Victorian weekly average change in residential consumption from 2019**




Source: Victorian DNSP monthly energy consumption report, AER Analysis

In combination, the patterns of impact in Figure 4-7, Figure 4-8 and Figure 4-9 show that:

- Compared to other networks, CitiPower's revenue depends to a greater extent on business customers than residential customers.
- The impact of lockdowns on CitiPower's residential customer consumption was consistent to that of the other networks.
- However, the impact of lockdowns on CitiPower's business customers, both SME and large, was more acute than for other networks.

These distinct impacts of COVID-19 on CitiPower compared to other DNSPs translated into a material under-recovery of revenue in 2020. We set out our analysis of this effect and its impacts in the next section.

## 4.4 Impact of changing consumption on revenue caps

All DNSPs are regulated under the revenue cap form of control. A network operating under revenue cap regulation may recover more or less than its allowed revenue target in any given year, due to differences between forecast and actual demand. Any over or under recoveries are then offset in future annual pricing processes, typically in the second year after the over or under recovery. Over time this means that a network can never recover more or less revenue than allowed in net present value terms.

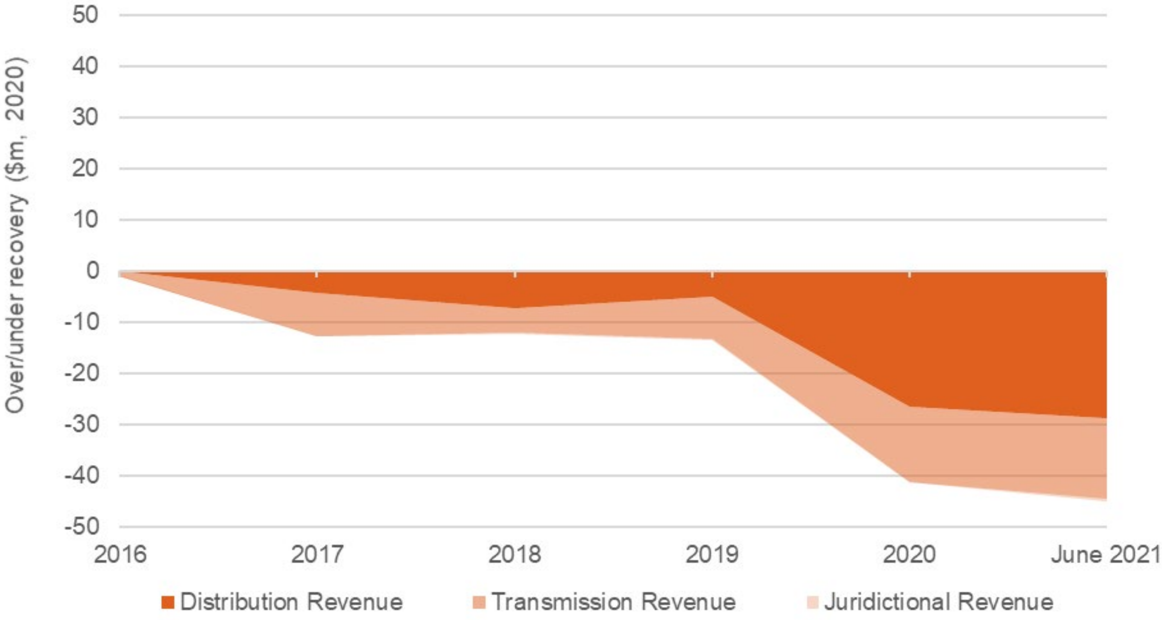
Each regulatory year, DNSPs are required to submit a pricing proposal to adjust and detail the prices they propose to charge at the start of the next regulatory year. In this pricing proposal, DNSPs are required to forecast the following year's consumer numbers and usage patterns, and determine the prices charged to each consumer type.

In light of the impacts observed in this section, we note that:

- Changes in usage patterns, including consumption, can lead to individual customers or types of customer paying more or less under the revenue cap
- Material under-recoveries, such as CitiPower's, result in material upward adjustments in future years' revenue caps.

The decreased consumption by CitiPower's customers in 2020 had a significant impact on their revenue collection for the 2020 regulatory year. CitiPower's under/over recovery balance through time is set out in Figure 4-10.

**Figure 4-10 CitiPower revenue cap over/under recovery balance**




Source: Approved pricing proposals, AER Analysis

This shows an under recovery of $26.8m in 2020, with an estimated additional under recovery of $4.2m in the six months to June 2021. This created a total under recovery balance of $45m for its network revenue, comprising of distribution, transmission and jurisdictional revenue at June 2021.

This $26.8m under recovery contrasted to CitiPower's expectations to recover an additional $11.8m[23] to balance for previous under recoveries.[24] This indicates that CitiPower recovered $38.6m less than expected in the 2020 regulatory year.

This under recovery of revenue was noted by CitiPower in their revised regulatory proposal for their 2021-2026 regulatory control period.[25] To minimise the immediate financial impact on its commercial and retail consumers, CitiPower applied that any under-recovered revenue due to the COVID-19 pandemic be deferred.[26] This would adjust the revenue for up to four years to smooth the impact of distribution tariffs.[27] The same applications were also made by Powercor[28] and United Energy, but were not accepted.[29]

Further, COVID-19's impact on future regulatory years is not limited to a possible under collection of revenue, creating higher prices in subsequent years. In its annual pricing approval process,

23 This consisted of planned over recoveries of $3.3m of distribution revenue charges, $8.2m of transmission revenue charges and 0.4m of jurisdictional revenue charges.

24 CitiPower, *Annual Distribution Pricing Proposal 2020,* 2019, p 11*;* CitiPower, *Annual Distribution Pricing Proposal 2020,* 2019, p 14.

25 CitiPower, *Revised Regulatory Proposal – 2021-2026*, 2020, p. 38.

26 CitiPower, *Revised Regulatory Proposal – 2021-2026*, 2020, p. 62.

27 CitiPower, *Revised Regulatory Proposal – 2021-2026*, 2020, p. 62.

28 Powercor, *Revised Regulatory Proposal – 2021-2026*, 2020, p. 72.

29 United Energy, *Revised Regulatory Proposal – 2021-2026*, December 2020, p. 58.

each DNSP forecasts consumption and other charging parameters across all of their tariff types. The prices that each type of consumer pays for their fixed and variable network costs are dependent on these forecast usage patterns. We discuss the potential for these enduring impacts in the next section.

## 4.5 Enduring impacts

Importantly, the effects of COVID-19 on networks and network consumers may continue to play out through 2021 and beyond. Beyond the ongoing impacts of lockdowns, the resulting ‘new normal’ following lockdowns may have contributed to enduring changes to how Australians conduct their day-to-day activities. For example, with more network consumers working from home instead of centralised CBD offices, there may be ongoing changes to their energy needs and energy consumption.

For example, in several DNSPs’ pricing proposals for the 2021-2022 regulatory year, networks submitted that:

- COVID-19 has led to lower overall energy consumption forecasts than the historical trend.[30]
- Forecasts for residential and non-residential consumption in 2021-22 are being impacted by the consumption noted in the 2020 regulatory year.[31]
- Lower energy consumption is expected in the tourism areas of Queensland due to COVID-19.[32]
- There is inherent uncertainty around the validity of forecasts due to COVID-19.[33]

We will continue to monitor these impacts in future regulatory years.

## 4.6 Network support mechanisms applying over 2020

To provide support to the energy sector and consumers there were two main support mechanisms for networks in 2020 regulatory year;

- The ENA’s COVID-19 electricity and gas network relief package
- The AEMC’s deferral of network charges rule change

Neither mechanism was widely used. With retailers broadly able to make their scheduled payment of network charges, there appears to be no apparent COVID-19 related impairment of the networks’ receivable assets.

30 Energex, *Annual Distribution Pricing Proposal 2021-22,* 2021, p 39; SA Power Networks*, Annual Distribution Pricing Proposal 2021-22,* 2021, p 21.

31 TasNetworks, *Annual Distribution Pricing Proposal 2021-22,* 2021, pp 34-36; SA Power Networks, *Annual Distribution Pricing Proposal 2021-22,* 2021, pp 2-3; Energex, *Annual Distribution Pricing Proposal 2021-22,* 2021, p 22; Essential Energy, Network Pricing Report 2021-22, pp 13-15.

32 Energex, *Annual Distribution Pricing Proposal 2021-22,* 2021, p 22; Ergon Energy, *Annual Distribution Pricing Proposal 2021-22,* 2021, p 22;

33 Energex, *Annual Distribution Pricing Proposal 2021-22,* 2021, p 22; Ausgrid, *Annual Distribution Pricing Proposal 2021-22,* 2021, p 25

Both mechanisms were designed and implemented when there was a high degree of uncertainty around the spread of the virus, lockdowns and their economic impact. Further the mechanisms were not designed to provide direct financial support to businesses and consumers, rather they were there to provide the necessary relief for debts related to COVID-19.

With the economic support measures[34] in place for businesses and consumers, the anticipated cash flow pressures on these consumers were reduced. This then reduced the likelihood and size of any debts related to COVID-19 for businesses and consumers.

This support, with the design of the mechanisms as a fail-safe, significantly reduced the number of consumers who required assistance. This enabled retailers to continue to make its scheduled payment of network charges to networks, with immaterial impacts on network revenues and their receivable assets.

## ENA's COVID-19 electricity and gas network relief package

In April 2020 the ENA and networks across NSW, Victoria and South Australia voluntarily introduced the COVID-19 Electricity and Gas Network Relief Package.[35] This package[36] provided a number of key support measures including:

- Rebating network charges to small business who were mothballed due to COVID-19 and experiencing financial stress.[37]
- Rebating network charges for residential consumers of small retailers that went into default as a result of COVID-19.[38]
- Deferring network charges for residential consumers of large retailers who go on payment plans or hardship arrangements as a result of COVID-19.[39]

These measures were designed to work alongside the *AER's Statement of Expectations*,[40] providing support to retailers in not disconnecting consumers affected by COVID-19. Further support also prioritised the safety of life support consumers and to minimise the frequency and duration of any planned outages.[41] These voluntarily measures, designed to conclude at 30 June 2020, were extended to 31 January 2021 for the Victorian DNSPs.[42]

34 Refer to https://treasury.gov.au/coronavirus for the components of the federal government's economic support package

35 https://www.energynetworks.com.au/news/media-releases/2020-media-releases/energy-network-relief-package-announced/

36 https://www.energynetworks.com.au/miscellaneous/covid-19-electricity-and-gas-network-relief-package/

37 ENA, *COVID-19 Electricity and Gas Network Relief Package*, 2020, p 3.

38 ENA, *COVID-19 Electricity and Gas Network Relief Package*, 2020, p 4.

39 ENA, *COVID-19 Electricity and Gas Network Relief Package*, 2020, p 5.

40 AER, Statement of Expectations, April 2020. https://www.aer.gov.au/system/files/AER%20-%20Statement%20of%20Expectations%20-%209%20April%202020.pdf

41 ENA, *COVID-19 Electricity and Gas Network Relief Package*, 2020, p 6.

42 https://www.energynetworks.com.au/news/media-releases/2020-media-releases/energy-networks-extend-customer-support/.

## AEMC’s deferral of network charges rule change

In May 2020, the AER submitted a rule change request to the Australian Energy Market Commission (AEMC), seeking amendments to the NER.[43] These amendments sought to defer the payment of some network charges to DNSPs for a six month period. This proposal intended to allow retailers to focus on providing energy supply and support consumers impacted by COVID-19.

The AEMC’s final rule allowed network charges incurred between 6 August 2020 and 6 February 2020 to be deferred for specific consumers impacted by COVID-19.[44] This was in place during the 2020 regulatory year for Victorian DNSPs and the 2021 regulatory year for all other DNSPs.

The uptake of the AEMC scheme by eligible retailers was limited. In Victoria there were two applications made to defer approximately $107k of network charges,[45] with no deferral applications made in the NECF states.[46] The low uptake of the mechanisms may be a consequence of several different factors, including but not limited to:

- The mechanism being designed as a failsafe, rather than a mechanism to be used proactively.
- Commonwealth and state government economic support measures in place for consumers and businesses.
- Retailers being able to draw on other support from parent companies or associated entities.

43 AEMC, *Consultation Paper – National Electricity Amendment (Deferral of Network Charges) Rule 2020*, 2020, p 5.

44 AEMC, *Rule Determination – National Electricity Amendment (Deferral of Network Charges) Rule 2020*, 2020, p 12.

45 ESCV, *Energy customers during the coronavirus pandemic - Update – observations up to week ending 31 January 2021*, 2021, pg 2; ESCV, *Energy customers during the coronavirus pandemic - Update – observations up to week ending 28 February 2021*, pg 2.

46 AER, *COVID-19 Retail Market Data Dashboard – 29 March 2021*, 2021, p 4.

# 5 Seasonal reliability and analysis of major events

Our service target performance incentive scheme rewards or penalises DNSPs based on reliability performance and is calculated using annual outage data. As a result, we have previously reported network reliability outcomes on an annual basis. However, the nature of annual data means we have been unable to identify underlying trends or events that occur throughout the regulatory year.

Reliability is a key service output that consumers should receive for their expenditure on network services. In our view, more granular analysis of network outages is important to form a more complete and nuanced view of when and how consumers experience network outages.

We have analysed seasonal patterns of reliability to provide stakeholders with a more nuanced understanding of network reliability. We have also taken the opportunity to explore the extent to which our existing datasets can improve our understanding of major events such as the 2019/20 summer bushfires.

Over 2014 to 2020, we find that:

- reliability varies through the year in response to changes in seasons and weather
- seasonal patterns in reliability are consistent across jurisdictions and most feeder types
- there is no conclusive evidence of reductions in outage duration (normalised SAIDI) between seasons
- we do observe declining numbers of unplanned outages (normalised SAIFI), and these have occurred predominately outside of summer
- it is complex to identify and measure the effects of differing 'types' of events, such as bushfires, with our existing dataset. We plan to undertake further work on what inferences we can draw regarding major outages (MED) collectively or specifically

For this year's report, we have drawn on our dataset of individual network outages sourced from our category analysis RINs. This is a large and detailed dataset which annual performance reporting has allowed us to analyse comprehensively. Our analysis focuses on unplanned outages at both the normalised and total outage level. This analysis does not include planned outages, which are an important factor in a consumers' total experience of reliability, and a topic we will look to explore in future reports. The data also does not include:

- TasNetworks outage data—due to historical differences in data collection. We will look to address these differences and add TasNetworks to the dataset for future analysis.
- NT PWC data—noting that NT PWC commenced its first regulatory period under AER regulation in 2020.

**What makes up total unplanned outages?**

- Normalised outages - The frequency and duration of unplanned outages which we determine under our service target performance incentive scheme (STPIS) to be within the NSPs' control at their funding levels.
- Total excluded outages - The total frequency and duration of unplanned outages experienced by distribution network customers which we determine under our STPIS to be outside the NSPs' control. It includes:
    - excluded outages – events outside a networks control, such as transmission outages or other upstream events
    - major event days – major event day thresholds are calculated using a statistical formula. If daily SAIDI exceeds this threshold it is considered a major event day and excluded from normalised outages
- More information on normalised outages, excluded outages and major event days can be found in our review of the STPIS.

## 5.1 Are there seasonal patterns of reliability?

Our STPIS[47] does not provide incentives for the timing of outages within a given year. However, network outages can impact consumers differently depending on what time of year it is and where they are located within a network. For example, consumers may have a preference for few outages in summer if they live in a particularly warm region.[48]

### Frequency of outages

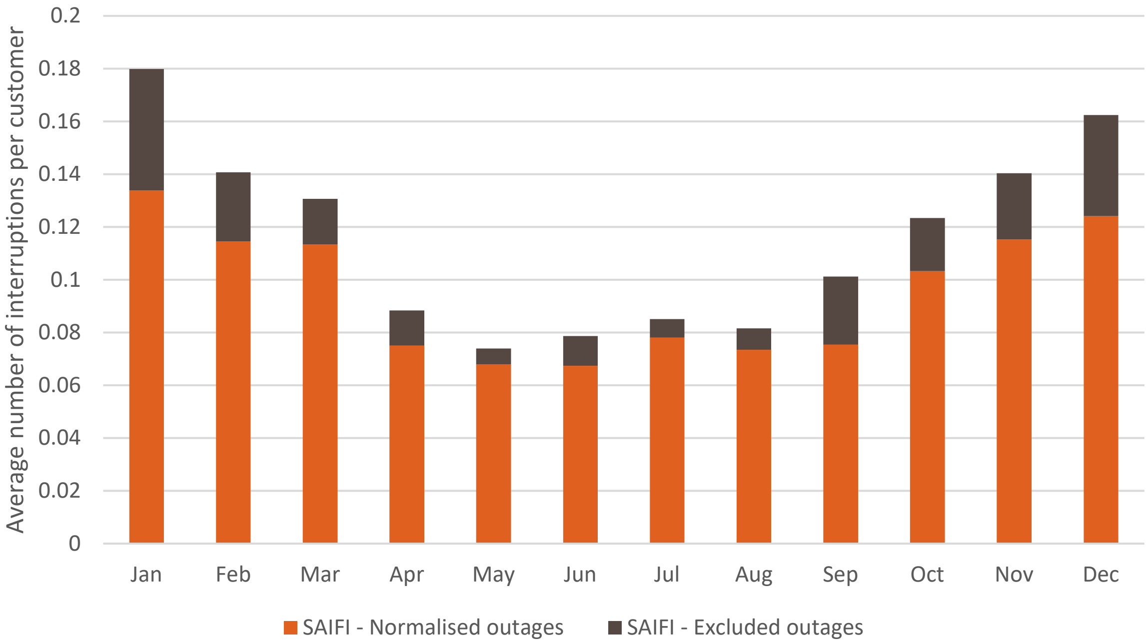
Analysis on the frequency of outages consumer face shows that consumers experience a higher number of outages in the warmer months.

Figure 5-1 shows average NEM SAIFI weighted annually using DNSP consumer numbers.

47 Information on the normalised outages, excluded outages and major event days can be found in our revised Service target performance incentive scheme.

48 AER, Value of Customer Reliability Review – Final Decision, December 2019

**Figure 5-1 Total unplanned monthly SAIFI – NEM average 2013 to 2019**




Source: AER analysis.

Figure 5-1 shows that at a NEM wide level:

- Customers experienced more normalised outages and more total outages in the warmer months. This means that on average customers will experience a higher number of outages in summer than winter.
- The effect of major event days is more pronounced in the warmer months.

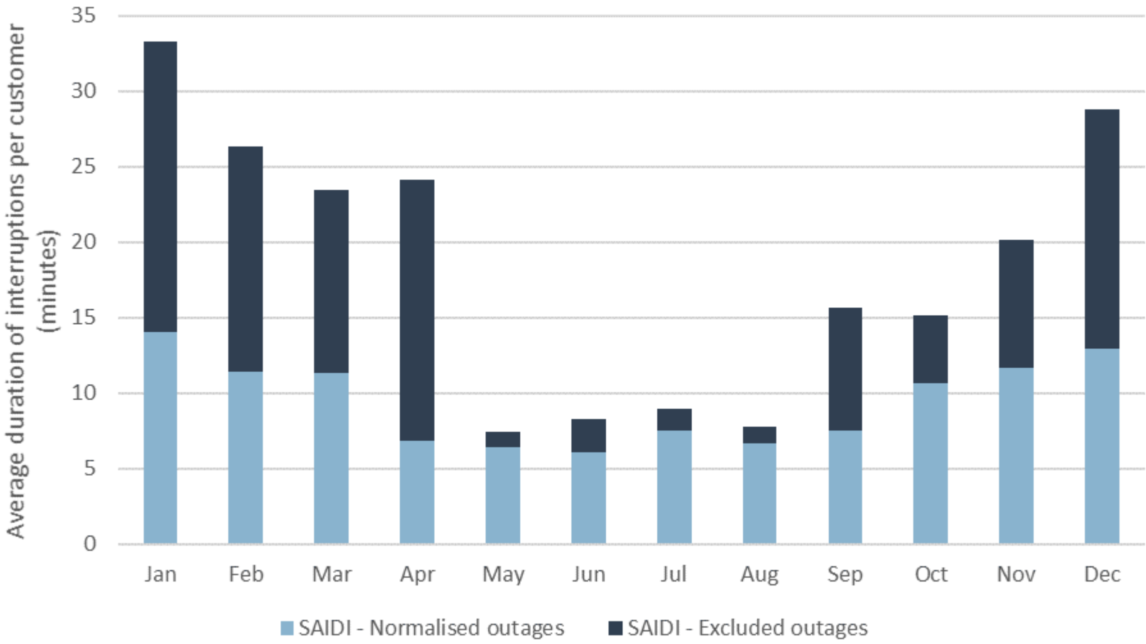
This is consistent with what we might expect, given storms and bushfires are typically more common and severe over those warmer months across much of the NEM.

## Duration of outages

Analysis on the duration of outages shows that consumers also experience longer outages in warmer months.

Figure 5-2 shows average NEM SAIDI weighted annually using DNSP consumer numbers.

**Figure 5-2 Total unplanned monthly SAIDI - NEM average 2013 to 2019**




Source: AER analysis.

It shows that:

- The duration of normalised outages (light blue series) exhibits a similar seasonal trend to the frequency of normalised outages.
- Consumers experience longer normalised and total outages in the warmer months.
- Outages on major events days disproportionately affect the duration compared to the frequency of an interruption, particularly in the warmer months. For example:
  - On average 41% of a consumers' total duration of outages occurs on a major event day
  - In contrast, only 17% of total outages occur on a major event day

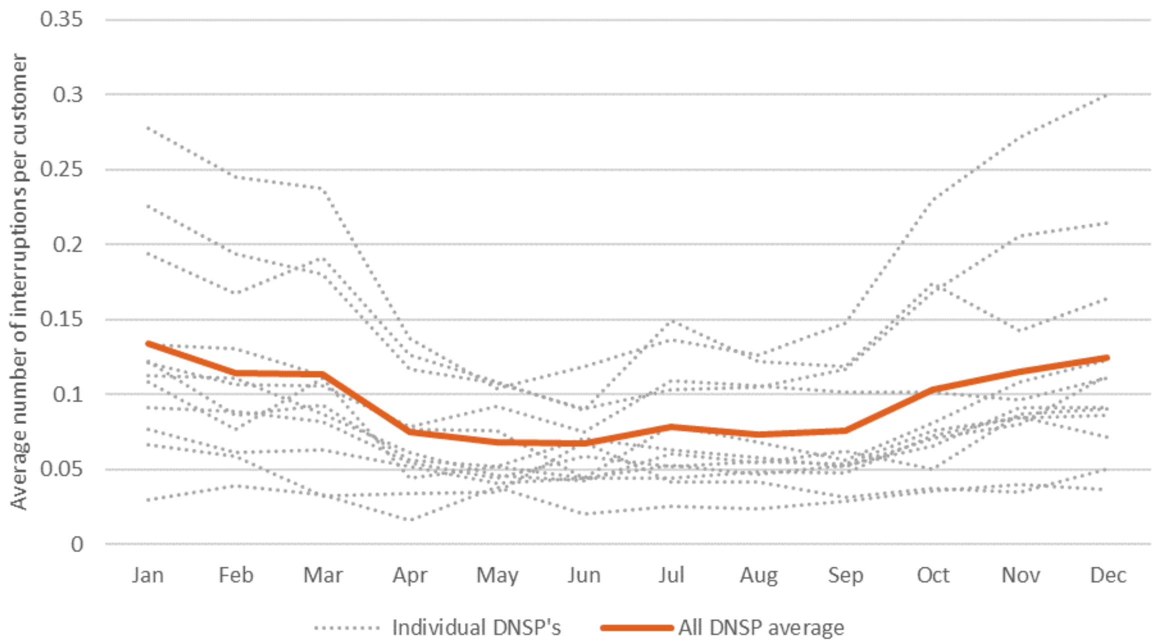
Importantly, not all consumers will be affected by the same outages in a given year, so an average across all consumers may understate the impact of outages experienced by those affected. This is particularly the case for major events as they are often specific to a particular jurisdiction or network. For example:

- 89% of the excluded SAIDI in April was caused by a significant storm event on Ausgrid's network in 2015, resulting in 6 continuous major event days.
- 78% of the excluded SAIDI and 53% of the excluded SAIFI in September was caused by the system black event on SA Power Networks network affecting consumers on 28 and 29 September 2016.
- 58% of the excluded SAIDI in March was caused by outages on Ergon Energy's network. Major event days occurred on its network from 27 March to 30 March in 2017 as a result of Cyclone Debbie.

## 5.2 Are patterns of seasonal reliability common between networks?

Consumers on different networks experience different reliability outcomes. Figure 5-3 illustrates these differences using the frequency of normalised supply interruptions amongst the different DNSPs.

**Figure 5-3 Average normalised monthly SAIFI by DNSP - 2013 to 2019**



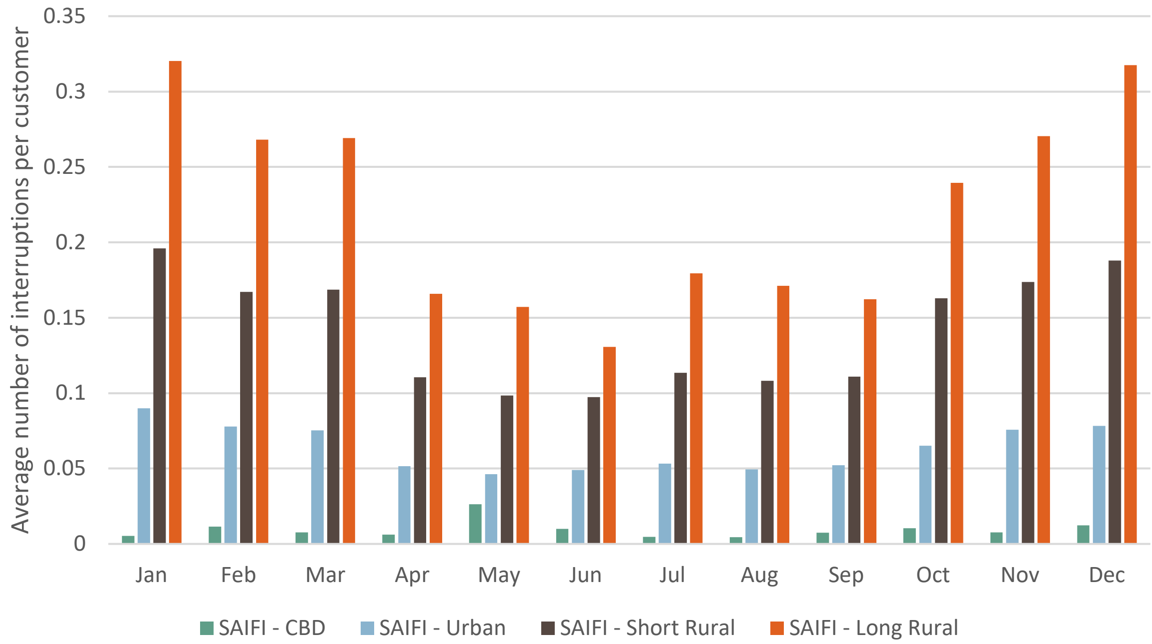

Source: AER analysis.

This shows that while customers on most networks experience more outages in warmer months, the average number of outages in any given month varies between customers of different networks.

Differing reliability outcomes across networks are driven by a number of factors including the characteristics of a network. For example, if a network serves a large rural consumer base, they are more likely to have more frequent and longer outages. As noted in section 3.4 consumers also experience different reliability outcomes depending on where they are located within a network.

Figure 5-4 illustrates this impact using average normalised frequency of supply disruptions across different consumer feeder types.

**Figure 5-4 Average normalised monthly SAIFI by consumer feeder type - 2013 to 2019**



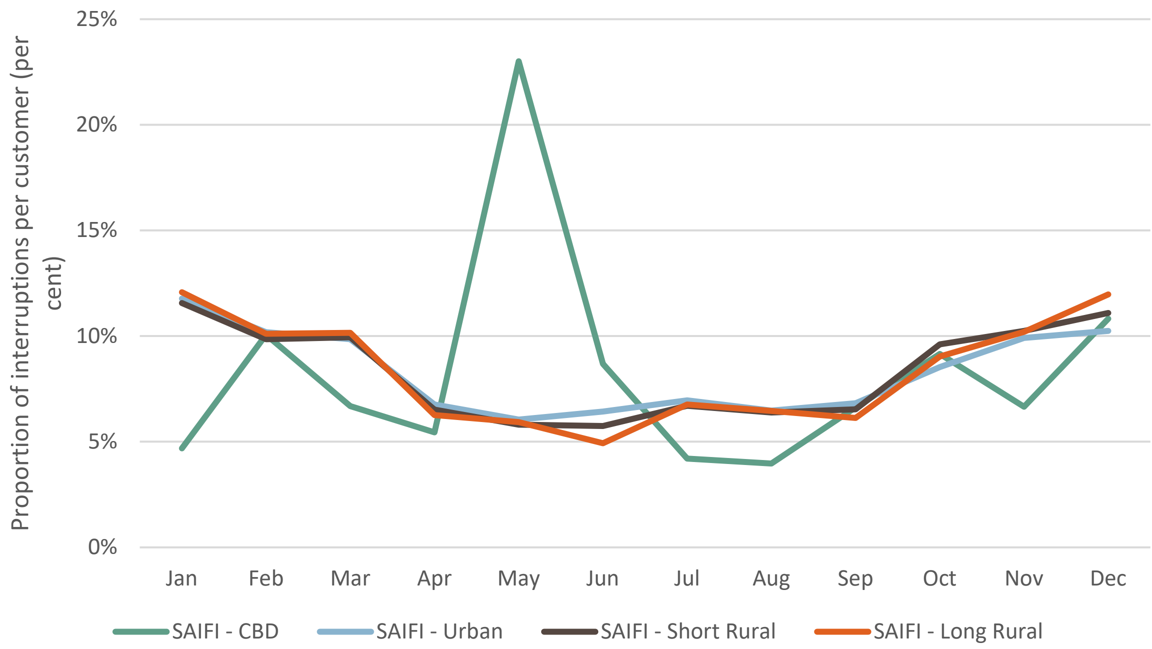

Source: AER analysis.

It shows that on average:

- Customers experienced more frequent outages the further they lived from city centres.
- Most customers across all feeder types have experienced more outages in the warmer months.

Figure 5-5 highlights this further. It shows the proportion of average normalised frequency of supply interruptions by consumer feeder type.

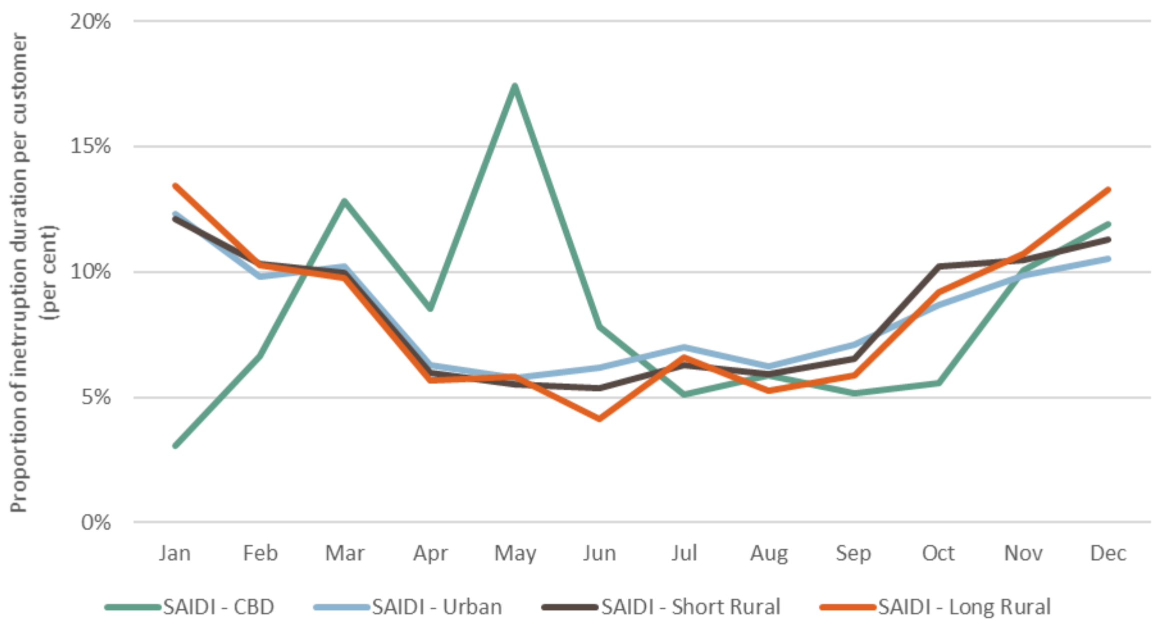
**Figure 5-5 Proportion of average normalised monthly SAIFI by consumer feeder type - 2013 to 2019**




Source: AER analysis.

Similarly, Figure 5-6 shows the proportion of average normalised duration of supply interruptions by consumer feeder type.

**Figure 5-6 Proportion of average normalised monthly SAIDI by consumer feeder type - 2013 to 2019**




Source: AER analysis.

In combination, these patterns show that:

- Although experiencing different average reliability outcomes, customers on urban and rural feeders experience similar seasonal trends in the number of normalised outages.
- Urban and rural customers also experience similar, though more variable, seasonal trends in the duration of normalised outages.

## More variable patterns of CBD reliability

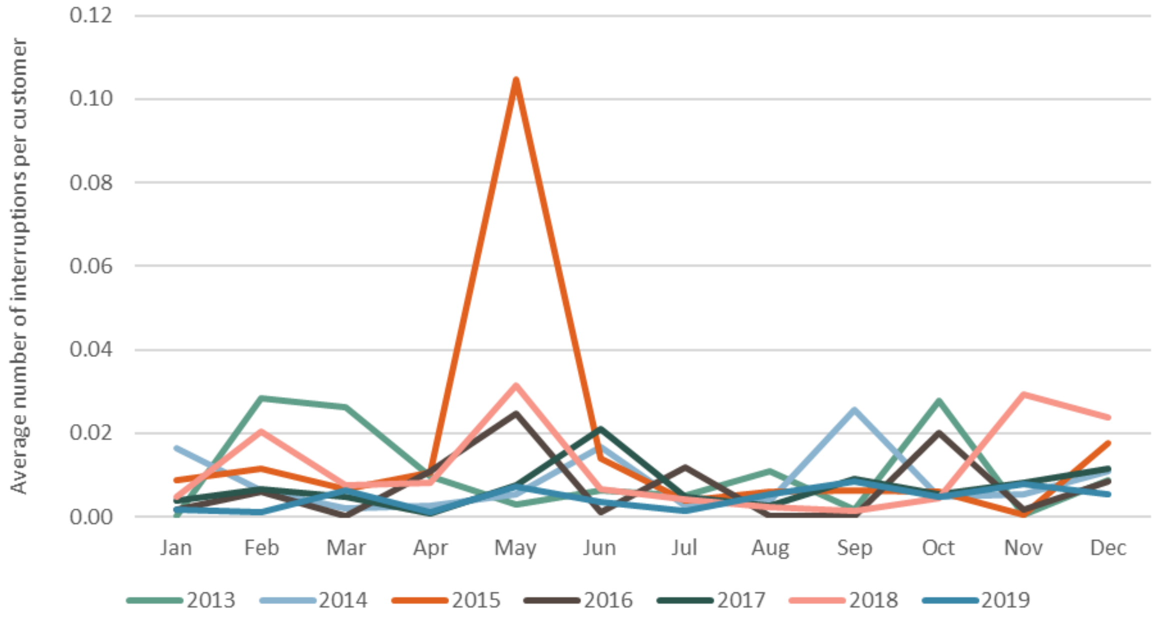
CBD consumers have experienced less seasonal variability in normalised reliability than consumers on urban or rural feeders. This is expected as CBD networks have a higher proportion of network undergrounding and increased redundancy. These same reasons contribute to why CBD consumers experience the lowest number and duration of outages across the NEM. Similarly, weather related events are less likely to have a significant impact on CBD consumers.

While the nature of CBD networks reduce seasonal variability, the low number of outages and high consumer density means that when material outages do occur it can result in proportionately large changes in CBD outages when viewed in time-series. This is evident in the large May peaks in Figure 5-5 and Figure 5-6. These peaks are predominately driven by an event in Melbourne 2015. In that instance, CitiPower experienced two substations going offline simultaneously, which resulted in 9,200 consumers losing power for approximately 35 minutes. [49]

Figure 5-7 shows the year to year variability in SAIFI on CBD networks. This highlights the example of where a higher than normal increase in outages per consumer in a given year, can have a proportionally large impact on aggregate outcomes. The pronounced spike in May 2015 is sufficiently high relative to the ordinarily low baseline of outages on CBD networks that it shapes the May outcomes in Figure 5-5 even when averaged over the full time series.

[49] ABC News, *Southbank, Melbourne outage affected 10,000 people, CitiPower says, after power restored,* 5 May 2015

**Figure 5-7 Average normalised monthly SAIFI – CBD consumers**




Source: AER analysis.

The distribution of CBD consumers when looking at NEM averages also contributes to this variability.

- Roughly 60% of CBD consumers are on CitiPower's network, with roughly 30% on Ausgrid's network.
- The remaining CBD consumers are split between SA Power Network and Energex networks.

This means that NEM average results on CBD feeders are highly influenced by events on a small number of networks, making them particularly sensitive to localised outages.

Similarly the composition of particular networks also has an effect because CBD consumers make up a small part of a distribution network. For example, 18% of CitiPower's consumers are on a CBD feeder, while only 2% of Ausgrid's consumers are on a CBD feeder. This is important, because an event that only affects CBD consumers on a specific network is unlikely to trigger its major event day threshold. This means that significant events that occur only on CBD feeders are likely to be included in normalised reliability outcomes.

## 5.3 Is seasonal reliability changing over time?

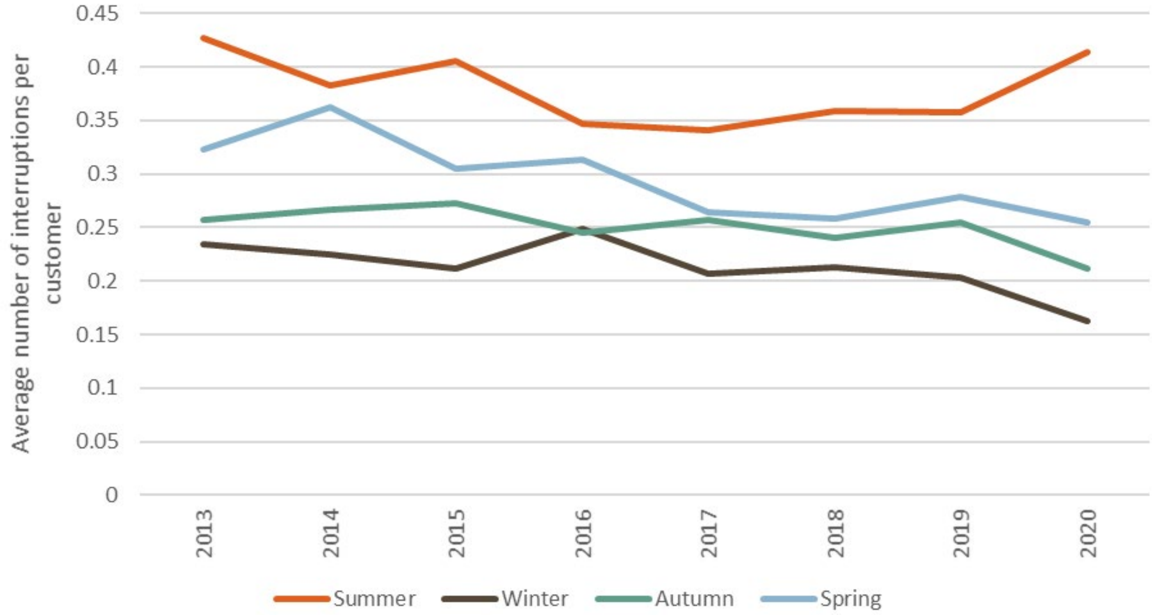
The STPIS works in combination with our expenditure incentive schemes to encourage networks to improve reliability where it is efficient to do so.

Having analysed the patterns of seasonal reliability across our full time series, we have also investigated whether those patterns are changing over time. In section 3.4, we observe using NEM-wide average data that there has been a steady reduction in the frequency of outages from 2011 to 2020. We have used our dataset to question whether those improvements are driven by improvements in a specific season, or whether they are spread throughout the year.

## Seasonal frequency of outages through time

Figure 5-8 shows seasonal trends in reliability using average normalised frequency of supply interruptions across the NEM.

**Figure 5-8 Average NEM normalised seasonal SAIFI**




Source: AER analysis.

Note: Analysis in this figure reflects regulatory years. This means there are slight differences in seasonal timings. For example for VIC networks summer 2020 is made up of January, February and December 2020. Summer 2020 for all other networks is made up of December 2019 and January and February 2020.

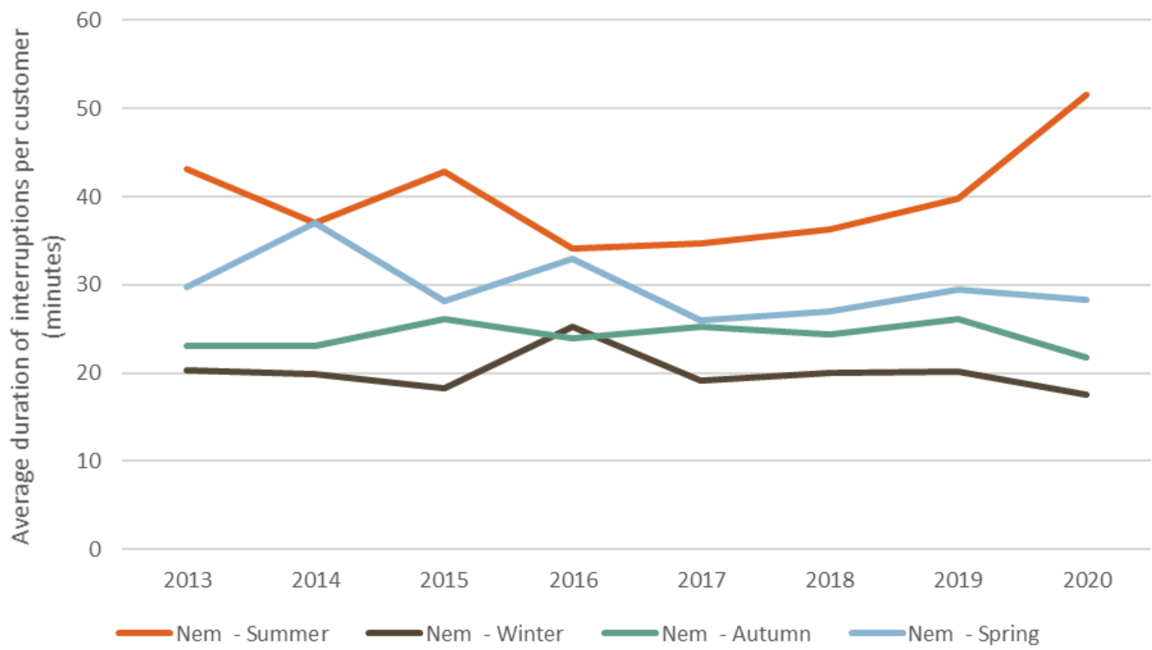
Over this time series we see evidence of improvements in all seasons other than summer. However, in any analysis of trends over time, conclusions can be sensitive to the choice of start and end point. For example, if our series commenced in 2014, it would appear as though summer outages had increased across the series.

Section 3.4 showed that normalised SAIFI decreased from 2019 to 2020. This decrease was driven by fewer outages outside of the summer months.

## Seasonal duration of outages through time

Figure 5-9 repeats this comparison using normalised duration of outages. In our view, it shows no clear evidence of seasonal trends in normalised SAIDI throughout the time series. However, the increase in normalised SAIDI from 2019 to 2020 was driven by significantly longer normalised outages in summer, with the duration of outages falling in all other seasons.

**Figure 5-9 Average NEM normalised seasonal SAIDI**




Source: AER analysis.

Note: Analysis in this figure reflects regulatory years. This means there are slight differences in seasonal timings. For example for VIC networks summer 2020 is made up of January, February and December 2020. Summer 2020 for all other networks is made up of December 2019 and January and February 2020.

## 5.4 Analysis of specific events or classes of events

We have also investigated whether our current outage dataset allows us to undertake analysis of different types of events. For example, we have tested whether the data can be filtered in such a way as we can clearly identify those outages caused by or linked to natural disasters such as storms or bushfires. In our view, this would be a valuable tool to better understand the impact of those outages on consumers' access to electricity supply during different types of major event.

Preliminary analysis using our existing datasets indicates that it is possible to identify and follow outages from a specific localised event—for example, an asset failure. However, interpreting the outcomes of geographically wide-reaching events or major event days is more difficult.

Major events such as bushfires or cyclones are typically complex and may impact a network in different locations across multiple days. This means that it is difficult to comprehensively track all outages at the feeder level which are either caused by or contribute to impacts from such an event. Further, when a major event day is triggered it encompasses all outages for that day across the whole network.

Nonetheless, our current dataset should allow us to draw conclusions about the frequency and impact of major event days through time. In our view, this would be an important improvement to our understanding of network service outputs and a possible focus area for future electricity network performance reports.

# 6 Returns on regulated equity

Through 2020 and 2021 we have collected from networks information which allows us to report the return on regulated equity (RoRE). This measure adds to the annual suite of network profitability indicators that we commenced reporting in our previous report.

Amongst those measures, it is unique because it illustrates the final returns available to equity holders after all expenses. This allows the most comprehensive comparison of the NSPs' actual returns against expected returns. Unlike the other profitability measures (RoA and EBIT per consumer), it is a ratio based on net profit after tax (NPAT) rather than EBIT. This means that the measure will also capture returns arising as a result of differences between:

- actual tax expense and the networks' forecast tax allowance, and
- actual interest expense and the networks' forecast return on debt allowance.

Importantly, RoRE is a complex measure and requires care to interpret. It is designed to reflect the treatment of network revenue and expenses in the building block revenue framework and in our models—for example, valuing network assets using the RAB rather than a separate book or market value. This is necessary so the results of the measure are comparable against our forecast returns on equity. However, it also means there are differences between our approach and how a return on equity would ordinarily be calculated. PwC has outlined the impacts of these differences in its advice published alongside this report.

In this section, we have set out our initial analysis of the measure alongside important background that stakeholders should be aware of when interpreting the results. We have published in our financial performance measures dataset annual RoRE estimates for all networks. We encourage all stakeholders to review results in this report and in our financial performance measures model alongside:

- Our profitability measures review final decision
- The RoRE explanatory note that we have published alongside this report
- The illustrative RoRE model we have published to illustrate the steps between calculation of the return on assets and the return on regulated equity. These additional steps are not detailed in our actual financial performance data model due to confidentiality of the underlying data.
- PwC's summary of responses to our information request

Further, the combination of the RoRE measure with the relatively simpler RoA measure should highlight different perspectives on profitability which balance our reliance on these new and complex allocations with a simpler but less comprehensive measure.

## 6.1 How to interpret the return on regulated equity

The regulatory framework is designed to compensate networks for efficiently incurred costs (such as operating expenditure, depreciation, interest on debt and tax) and to provide them with an expected profit margin in line with the required return in the market for an investment of similar risk. The expected profit margin, if set at an appropriate level, should attract efficient investment. This is the role that the allowed return on equity plays.

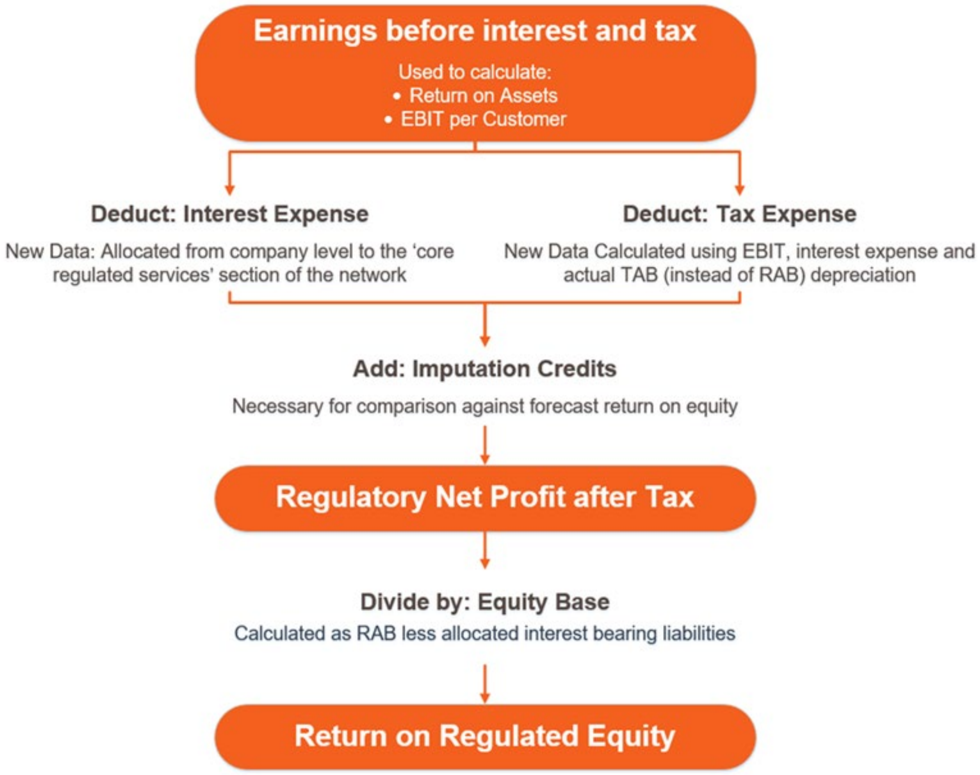
We expect networks' actual outcomes to differ from the forecasts and benchmarks we set. The revenue requirement is not a guaranteed return, as the networks' actual returns are determined in part by whether they spend more or less than these forecasts and/or depart from benchmarks.

This type of regulatory framework is often described as an incentive-based framework. In general, the inherent incentives in this regime encourage networks to outperform the forecasts and be financially rewarded through higher returns. The opposite occurs if the networks underperform against the forecast.

If a network is able to deliver its services at a lower cost than forecast, these lower costs of delivery should ultimately result in lower forecasts (holding other things constant) at the next revenue determination. By this process, both consumers and the networks share the benefits of efficiency gains over time.

The return on regulated equity builds on the information used to calculate the simpler return on assets and EBIT per consumer measures. Figure 6-1 illustrates the relationship between these simpler measures and the RoRE.

**Figure 6-1 Simple illustration of the return on regulated equity measure**




Source: AER analysis.

Then, if we are calculating real returns, there are other adjustments necessary for comparability between actual and forecast returns:

- To calculate the real return on assets, we remove indexation on debt and equity components of the RAB, and inflate the opening RAB so it is in common real dollar terms with EBIT

- To calculate the real return on equity, which follows on from the return on assets, we add back the indexation on debt and only inflate the equity base (as opposed to the entire RAB) to be in common real dollar terms with regulatory NPAT.

As with our other measures, we have calculated the RoRE:

- At the network level, rather than at the ownership group level—this is important, because many networks are held within a larger company structuring including numerous networks and/or other business units. Some expenses, such as tax and interest, are more commonly incurred at the ownership group level and not at individual network level. This is why we have had to request further information on tax and interest expense.
- To show returns arising in the provision of 'core regulated services'—that is, these are the returns for the basic network service using the regulated asset base. It should not capture returns arising from other segments of the network business.
- Treating revenue and expense drivers consistently with their use in our post-tax revenue model.

All analysis in this chapter excludes profitability for NT Power and Water Corporation which we have been able to calculate only for 2020 as the first year under an AER revenue determination.

We have not previously collected this data from networks in a consistent and comparable form. For some networks, actual tax and/or interest expenses are incurred at ownership-group level. For our purposes, we require an allocation within the corporate group to identify the expense incurred by the network in providing core regulated services.

Like the return on assets measure we publish, the return on regulated equity should be compared to the relevant forecast returns on equity set in our determinations.

Because of the distinct treatment of certain expenses in the regulatory model—for example, indexation of the regulated asset base—it is difficult to compare these estimates directly to statutory returns on equity included in annual reporting for listed companies. In our view, these regulatory measures are a valuable companion to company-level statutory reporting.

We are also intending to revisit the question of whether to introduce further network level statutory-measures to complement the regulatory measures. Our view from developing the regulatory measures is that additional statutory measures will significantly increase the complexity and data requirements involved in profitability reporting. However, we will engage widely with stakeholders in 2022 to test whether the benefits from further reporting exceed the likely costs in doing so.

## 6.2 Key findings

In the following sections we set out our key findings on return on regulated equity outcomes and their drivers.

All of this analysis in this section, including both real and forecast returns, is based on:

- Real returns—that is, excluding returns from indexation of the equity base

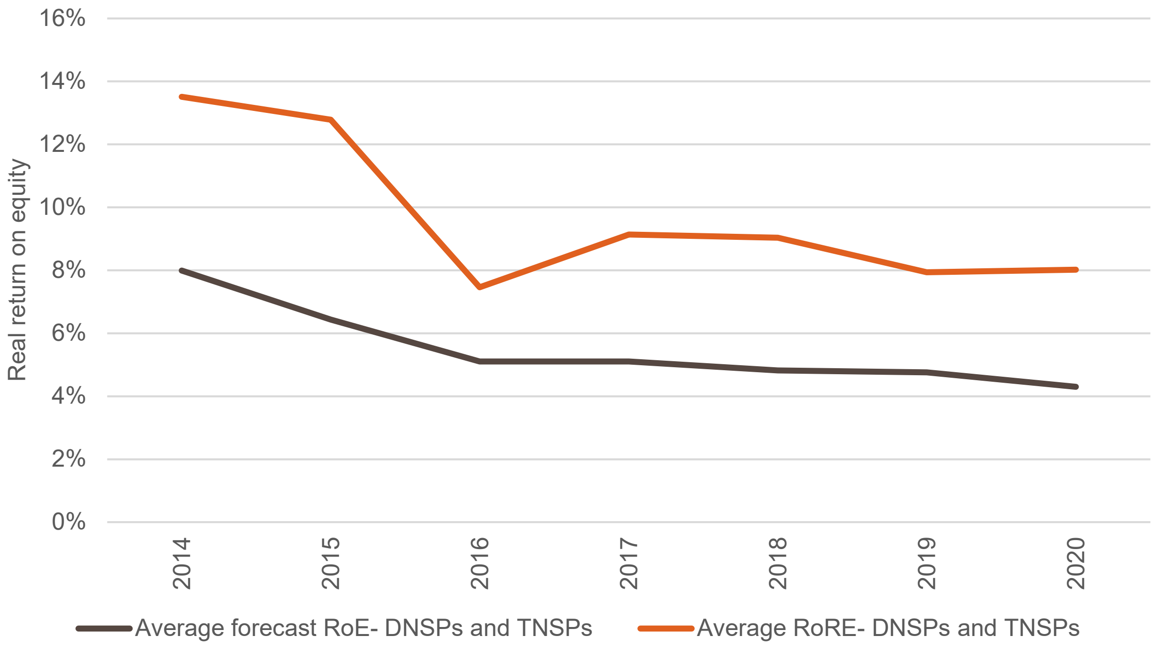
- Returns including rewards or penalties from incentive schemes
- Returns excluding the impacts of ‘pass-through’ revenues collected by DNSPs but from which the DNSPs do not earn profit over time—for example, TUOS revenue or jurisdictional scheme revenue.

Our financial performance data, published alongside this report, allows stakeholders to adjust all of those settings and compare actual returns to forecast returns.

## What returns are networks achieving?

Over 2014-20, networks have on average achieved higher returns on regulated equity than forecast.

**Figure 6-2 Real returns on regulated equity compared to forecast returns on equity—DNSPs and TNSPs**




Source: Financial performance data, AER analysis

Over 2014 to 2020:

- Average electricity network returns on regulated equity declined materially
- Despite this, electricity networks achieved returns on regulated equity which exceed forecast returns on equity by approximately 4.2%
- This occurred against a backdrop of declining forecast returns on equity. This decline has progressed as:
  - interest rates have declined, including the rates on Commonwealth Government Securities based on which we forecast the risk-free rate
  - we have applied the 2013 rate of return guideline and, from 2020, have begun to apply the 2018 binding rate of return instrument. So far, the 2018 instrument has applied to five DNSPs and one TNSP.
- The difference between forecast and real returns was higher in the earlier years and narrowed materially after the introduction of the 2013 rate of return guideline.

The results appear consistent with the outcomes we observe in network returns on assets and in RAB multiples, giving us greater confidence in the outcomes of the measure.

We also observe that:

- Underneath the average results, there is a spectrum of outcomes between networks, with some earning persistently higher returns
- All but one network have achieved returns at or above their forecast return in most if not all years[50]

In general, we would expect networks to achieve returns exceeding forecast returns in a well-functioning incentive-based regulatory framework. However, whether these results are evidence of the framework operating effectively or not depends on the drivers and materiality of the results, including whether they are caused by:

- Temporary revenue over-collections which will be passed back to consumers in the short-term
- Departures from our benchmark financing structures through which some networks have taken on higher risk to achieve higher returns
- Networks spending less than forecast revenue building blocks due to efficiency gains
- Networks spending less than forecast revenue building blocks due to shortcomings in our approach to estimating network revenue requirements

In the following sections, we set out our analysis of those factors that have driven differences between forecast returns and what the networks have achieved.

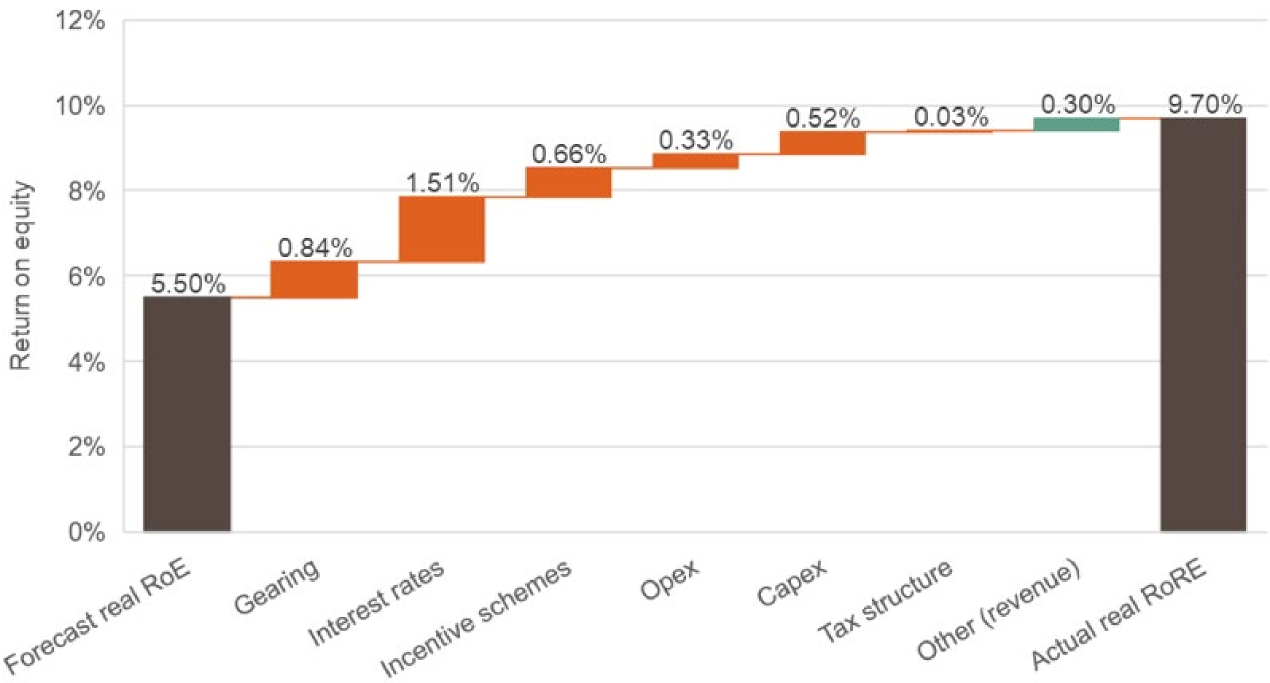
[50] In the initially published version of this report, this section wrongly stated that 'all networks have achieved returns at or above their forecast return in most if not all years'. Essential Energy achieved returns below forecast return in 5 of 7 years from 2014-20, but has generated average returns over 2014-20 slightly exceeding average forecast returns.

## What is driving these results?

Our analysis suggests that the differences between forecast and actual returns on equity is driven by a combination of the above factors. Figure 6-3 sets out the average impact of different drivers in explaining the margin between:

- forecast real returns on equity—that is, excluding returns from indexation of the RAB; and
- actual real returns on regulated equity

**Figure 6-3 Incremental contributions to returns on regulated equity—DNSPs and TNSPs**




Source: Financial performance data, AER analysis

Note: We have calculated the above by substituting for each factor, one at a time, our forecast of that factor for a network in place of the actuals that the networks have reported. So, for example, we have substituted in forecast opex form our PTRM in place of actual opex used in calculating the real RoRE. We calculate the incremental change in returns with each new factor for each network in every year of the time series.

While this average view of return drivers is informative, we also find that the effect and implications of the different factors changes from factor to factor and through the reporting period.

## 6.3 Temporary revenue effects

All electricity networks are regulated under ‘revenue cap’ forms of control. This means that:

- Each year, networks target a revenue cap based on our forecast revenue requirements, changes in actual inflation and a range of other factors which vary between jurisdictions.

- In reality, networks typically recover more or less than this amount in any given year because network usage (such as consumption or maximum demand) differs from the forecast used to convert the revenue cap into prices.
- If a network recovers more revenue than forecast, it returns this margin to consumers in 2 years' time through a lower revenue cap. Similarly, if it recovers less revenue than forecast, it recovers that margin from consumers in 2 years' time.
- As a result, networks can recover revenue different to the cap in any given year, but over time they will only recover the revenue cap.

**Background on temporary revenue effects**

There are three different ways in which revenue effects can lead to differences between forecast and actual returns on equity in any given year. These are:

- Collecting more or less revenue than targeted through the revenue cap
- Impacts of revenue smoothing
- Increases or decreases to the annual revenue target to account for past over or under recoveries

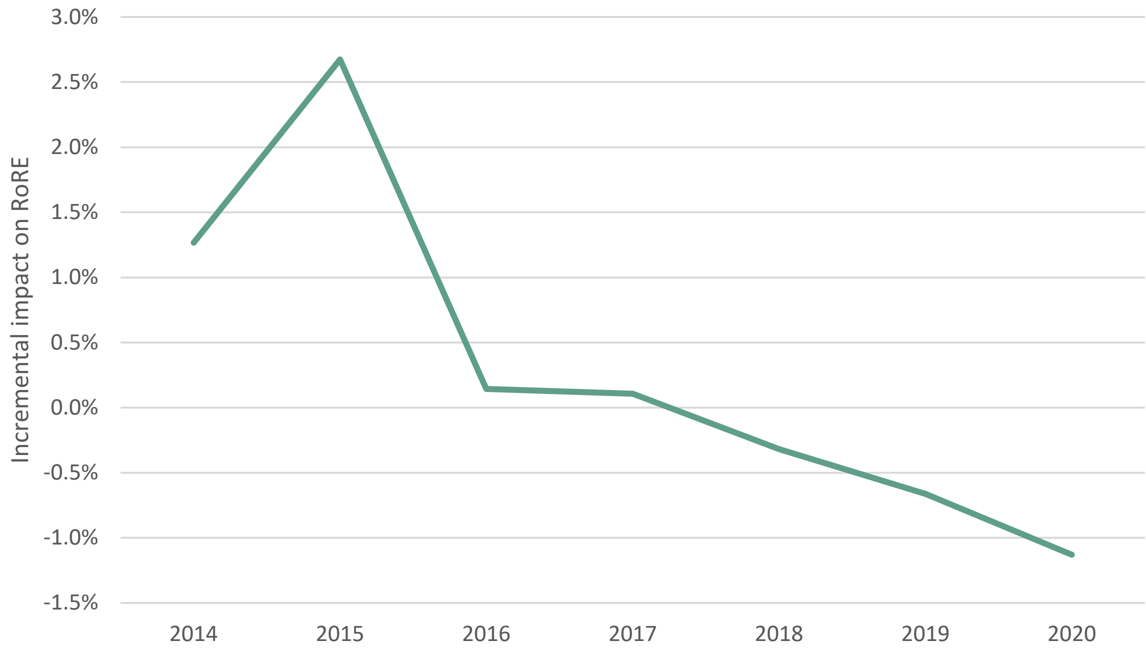
Importantly, all of these effects are temporary. This means for example that a temporary revenue impact might lead to a higher actual return in a given year, but that the difference will be reversed in future years. So, over time, none of these revenue effects result in higher or lower average returns.

From this, we observe that:

Over 2014 to 2020:

- Temporary revenue effects account for 0.3% of the average difference between network returns and forecast returns
- However, in some years the incremental contribution of temporary revenue effects is material either increasing or decreasing returns

**Figure 6-4 Impact of temporary revenue effects through time—DNSPs and TNSPs**




Source: Financial performance data, AER analysis.

The impact of the temporary revenue effects was at its highest in the early years of the period—this appears to be caused largely by the NSW/ACT transitional revenue determination, during which the networks were temporarily targeting revenue forecasts above the ultimate revenue caps determined during the remittal process. The remittal process included reviews of the AER's determinations sought by the networks under the limited merits review framework. In subsequent years, several networks were materially over-recovering revenue against the PTRM forecast while Tribunal proceedings were resolved, but these impacts appear to be offset by the impacts of revenue smoothing within the PTRMs.

**The NSW/ACT remittals**

In April and June 2015, the AER published final decisions on the 2014-19 distribution determinations for NSW and ACT electricity distributors (Ausgrid, Endeavour Energy, Essential Energy and EvoEnergy—then ActewAGL Distribution), and on the 2015-20 access arrangement for the NSW gas distributor, Jemena Gas Networks (JGN).

All five businesses sought merits review of the AER’s final decisions. The Public Interest Advocacy Centre (PIAC) also applied for review of the AER’s NSW final decisions. The Commonwealth minister intervened.

The Australian Competition Tribunal handed down its decisions in February 2016 (and March 2016 for JGN). It remitted the decisions to the AER to be remade, in particular in accordance with its orders regarding: the return on debt; the value of imputation credits (gamma); the four electricity distributors’ operating expenditure (and for EvoEnergy, the implications of this for the Service Target Performance Incentive Scheme (STPIS)); and aspects of JGN’s capital expenditure.

In March 2016, the AER sought judicial review of the Tribunal’s decisions on gamma, return on debt and operating expenditure in the Full Federal Court. The Court upheld the AER's appeal in respect of the Tribunal's construction of the rules regarding gamma, but dismissed the appeal in relation to the return on debt and operating expenditures of the electricity businesses.

As a result, the AER was tasked with revisiting its decisions regarding the return on debt, the four electricity distributors’ operating expenditure (and for ActewAGL Distribution, the implications of this for STPIS) and aspects of JGN’s capital expenditure.

## 6.4 Impact of interest expense

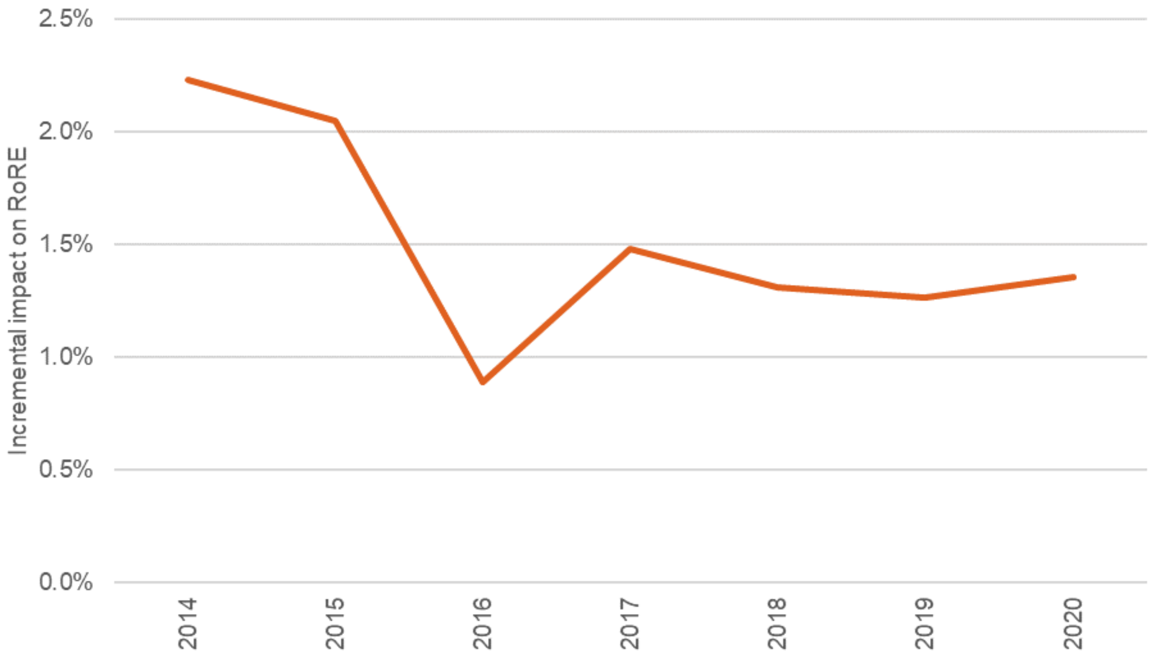
Networks raise capital to finance investment in their assets. They can do so with either debt or equity. They are compensated for these costs through the return on capital building block, which itself includes a return on debt to compensate networks for the interest expense that an efficient benchmark entity would require.

Networks may raise debt at higher or lower rates than we forecast. Our estimated returns on regulated equity increase where networks raise debt at lower rates than forecast and decrease where networks raise debt at rates higher than forecast.

Over 2014 to 2020, we find that:

- Networks have, on average, consistently achieved higher returns as a result of raising debt at rates below forecast.
- The magnitude of impact arising from this difference has varied through time.
- We expect that some of these differences will decline as networks complete their transitions into full trailing average debt portfolios under our binding rate of return instruments.
- However, there is some evidence of persistent outperformance which we are investigating through our pathway to the 2022 binding rate of return instrument.

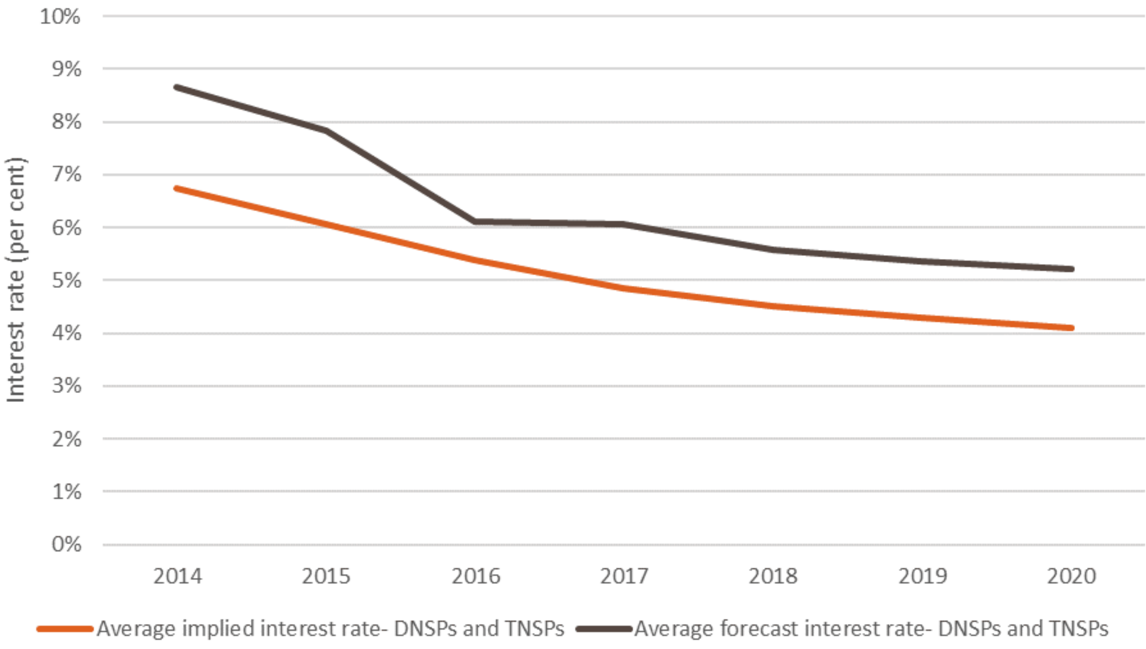
**Figure 6-5 Impact of interest rates through time—DNSPs and TNSPs**




Source: Financial performance data, AER analysis.

This is driven by average interest rates being consistently below forecast. We also observe that this is consistent in all cases outside of one network in one year.

**Figure 6-6 Comparison of forecast and actual interest rates—DNSPs and TNSPs**




Source: Financial performance data, AER analysis.

### How do we estimate actual interest rates?

In responses to our information request, networks allocated for each year:

- The interest expense arising in that year—that is, the interest a network paid on its debt.
- The value of interest bearing liabilities giving rise to that debt—that is, the amount of debt held by the network.
- From that information, we can estimate an effective interest rate on the portfolio of debt networks have allocated.

In our view, these results reflect a complex set of changes in market circumstances and our approach to forecasting rates of return on debt:

- In 2014 and 2015, most networks' forecast returns on debt were still based on decisions made in 2009 and 2010 when interest rates were significantly higher. At that stage, returns on debt were set using the 'on the day' approach and, as a result, resets occurring in a high interest rate environment would materially increase the networks' forecast interest rates across their entire portfolios of debt.
- Over 2014 to 2016 we completed resets for most electricity networks and reset returns on networks' portfolio of debt in a lower interest rate environment. This explains the rapid decline in average forecast costs of debt, and as a result the narrower margin between forecast and actual costs.
- This also marked the commencement of transitions to a trailing average portfolio return on debt, after which the rates on networks' portfolios of debt were and continue to be updated annually for a tranche of debt.

- Over 2016-17 there were a number of network privatisations during a period in which interest rates in the market were continuing to decline. As a result, several networks reset their actual costs of debt in this lower interest rate environment and widened the difference between forecast and actual interest rates.
- Then, in our 2018 binding rate of return instrument,[51] we found that our approach to targeting the benchmark credit rating was resulting in higher than necessary annual estimates of the cost of debt. As a result, we made changes to improve our approach. We expect those changes to gradually contribute to a narrower margin between forecast and actual interest expense over 10 years as they feed into the networks' trailing average portfolios.

In late 2020, we consulted on and published a position paper on energy network debt data.[52] That paper is part of a broader suite of work to advance our thinking in the lead-up to making the 2022 binding rate of return instrument. In the paper, we found corresponding evidence to suggest that networks have been raising annual tranches of debt at rates below our forecasts. If so, this could contribute to ongoing margins between forecast and actual interest expense.

## 6.5 Impact of financing structure

When we set forecast returns on capital, we apply a benchmark assumption that networks raise 60% of their capital as debt, and finance the remaining 40% as equity. We refer to this as the network's 'gearing'.

In doing so, we recognise that networks can choose to depart from the benchmark. For example, a network may finance a higher proportion of its capital requirements using debt. This means that a smaller proportion is raised through equity. Then, when profit is available to be distributed, the profits are distributed across a smaller base of equity ownership, resulting in higher returns per dollar of equity invested.

By departing from the benchmark in this way, the networks are taking on extra risk to achieve higher reward. Where networks raise more debt than our benchmark, equity holders are more exposed to changes in other drivers of revenue and costs because of the smaller equity base over which the impacts are distributed. The opposite is true if a network chooses to raise less debt than our benchmark.

For this reason, higher or lower returns arising from different financing structures are not necessarily evidence of a problem. Over time, if we observe a broader pattern of differences between our benchmark and actual practices, this may be cause to revisit our benchmark to reflect revealed efficient behaviours.

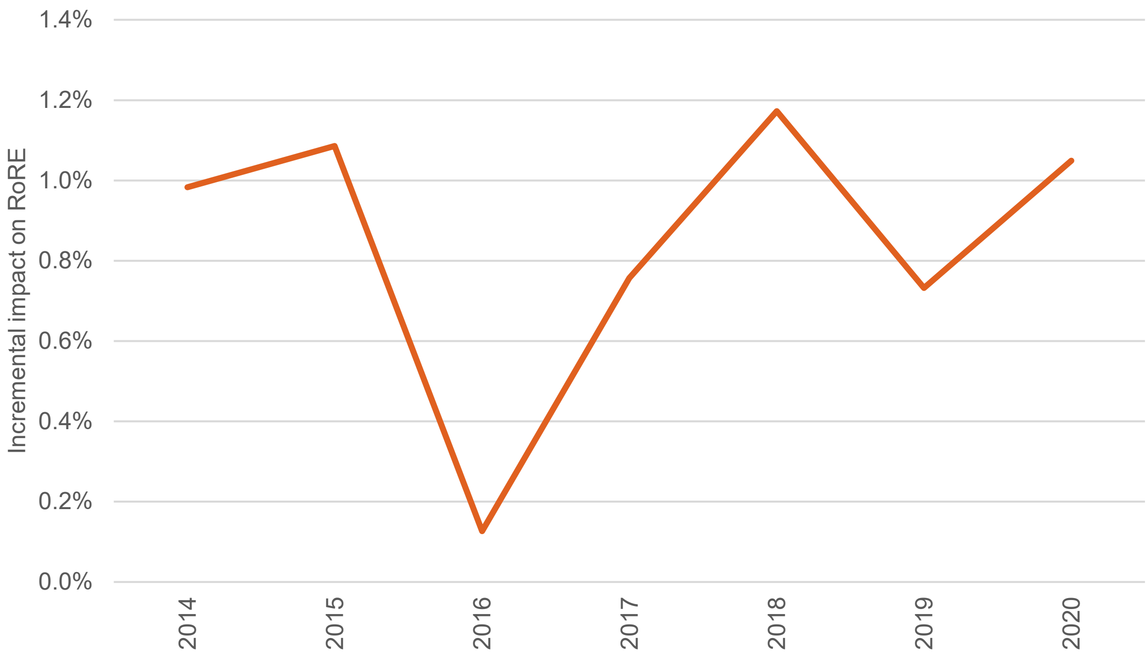
51 AER, Rate of return instrument—Explanatory statement, December 2018.

52 AER, Energy Network debt data—Final working paper, November 2020.

Over 2014 to 2020, we find that:

- On average, networks reported debt levels roughly consistent with our benchmark. However, there is a mix of financing strategies between networks and a wide range of gearing levels.
- Within this overall average, there is one network with notably low gearing and, correspondingly, the other networks raise on average slightly more debt than the benchmark.
- Returns are highly sensitive to financing strategy. Higher gearing amplifies the impacts of other differences between forecast and actual revenues or expenditures. This is why the profile of gearing impacts in Figure 6-7 is not smooth despite relative stability in gearing levels through the sample period.
- The combination of most networks raising on average somewhat more debt than the benchmark and the high sensitivity of results to financing strategy is why financing strategy has a material and positive impact on returns despite the average being close to benchmark.

**Figure 6-7 Impact of financing structure through time—DNSPs and TNSPs**




Source: Financial performance data, AER analysis.

**How we estimate actual equity and gearing**

In responses to our information request, networks allocated for each year:

- The interest expense arising in that year—that is, the interest a network paid on its debt.
- The value of interest bearing liabilities giving rise to that debt—that is, the amount of debt held by the network.

To mirror the treatment in our regulatory models, we use the opening RAB in a given year as the total value of the networks' assets. Then:

- To calculate the value of equity, we deduct the value of interest bearing liabilities from the opening RAB value.
- We can work out an implied gearing level as interest bearing liabilities divided by opening RAB value. This ratio does not directly impact the calculation, but is useful for our analysis.

## 6.6 Impact of capital expenditure

We set networks' forecast return on capital allowance based on the opening RAB at the commencement of a regulatory period and using forecast capital expenditure.

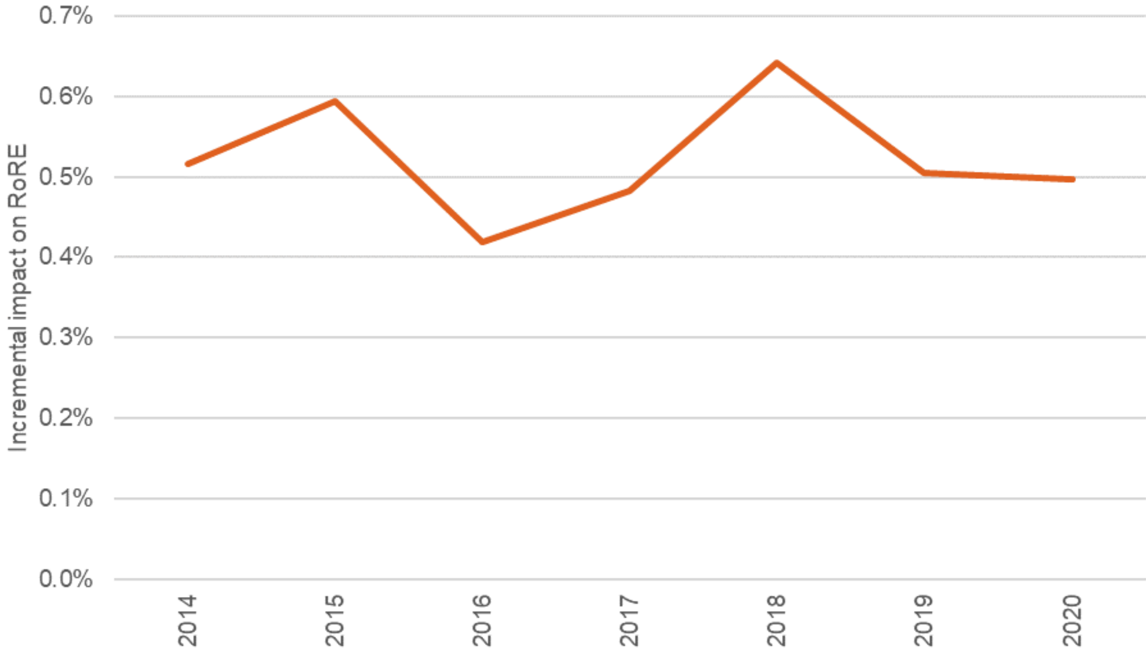
In practice, networks commonly spend more or less capex than forecast. These differences contribute to differences between forecast and actual returns because:

- If capex is lower (or higher) than forecast, the network will have to raise less (or more) capital than forecast; and
- as a result will keep (or lose) the incremental return on capital allowance relating to the difference until the end of the regulatory period when the RAB is rolled-forward.

Over 2014 to 2020:

- Electricity networks on average spent less capex than forecast. Through the incentives inherent to the framework, networks generated incremental increases in returns to equity holders.
- This impact captures only the forecast capex incentive inherent within the framework. The impact of the CESS combines with the inherent capex incentive to generate the overall impact from capex on returns.

**Figure 6-8 Impact of capital expenditure through time—DNSPs and TNSPs**




Source: Financial performance data, AER analysis.

This is an important part of the implicit incentive inherent in the building block revenue framework which encourages networks to make efficiency gains over time.

However, networks keep these benefits (or penalties) whether they are caused by real efficiency gains or not. In recent years we have undertaken extensive work on our expenditure forecasting tools and our incentive framework to set the best possible incentive framework to encourage network efficiency. Recent examples include our:

- Replacement expenditure modelling assumptions review[53]
- Publication of a capex assessment outline for electricity distribution determinations[54]
- Our ongoing work program on assessing DER integration expenditure

The capital expenditure sharing scheme (CESS) is designed to complement this inherent incentive so that the incentives are even throughout a regulatory period. We analyse the impact of incentive schemes on network returns in section 6.8.

## 6.7 Impact of operating expenditure

Similar to capex, networks commonly spend less or more opex than our forecast. Before the impacts of the EBSS, networks keep these gains or penalties within the regulatory control period

53 AER, AER review of repex modelling assumptions—Explanatory note, December 2019.

54 AER, capital expenditure assessment outline for electricity distribution determinations, February 2020.

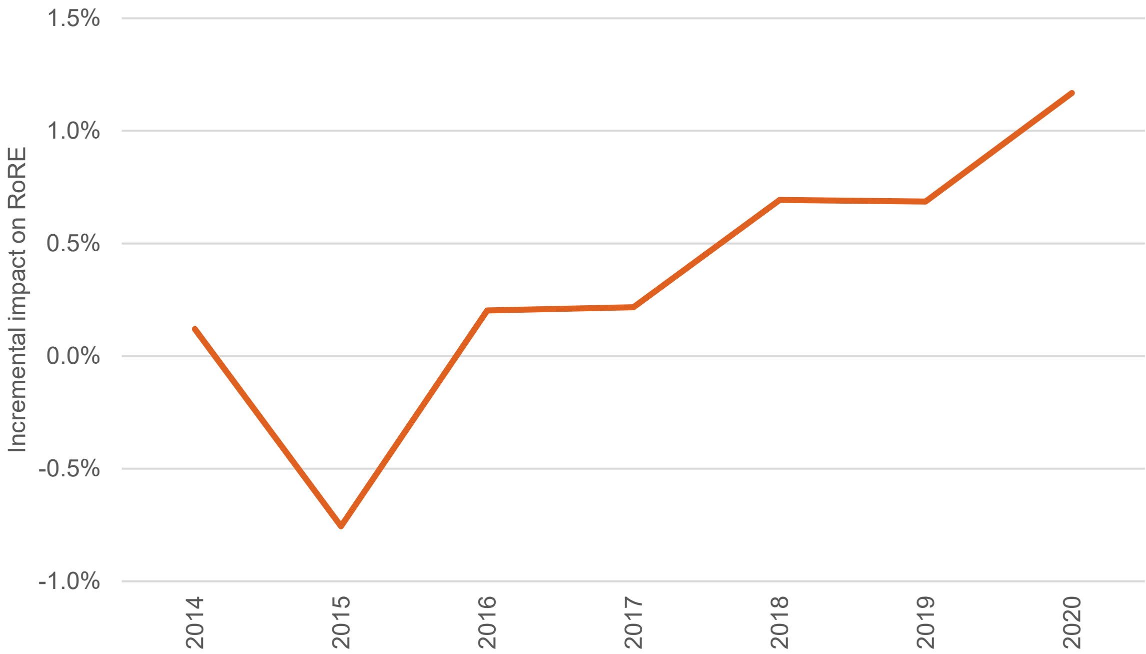
in which they occur. Through our resets, we then reflect any efficiency gains in lower forecast opex allowances, at which point the benefits of the networks' performance are shared with consumers.

Over 2014 to 2020:

- Electricity networks on average spent less opex than forecast. Through the incentives inherent to the framework, networks generated incremental increases in returns to equity holders.
- This impact captures only the forecast opex incentive inherent within the framework. The impact of the EBSS incentive scheme combines with the forecast opex incentive in generating the overall impact from opex on returns.

The EBSS works alongside our opex forecasting methodology with the networks keep the incremental benefits of sustained efficiency gains for the carryover period (usually five years) regardless of the year in which they occur.

**Figure 6-9 Impact of operating expenditure through time—DNSPs and TNSPs**




Source: Financial performance data, AER analysis.

Similar to the impact of capex, the impact of opex has changed over time as several networks have made material reductions in their opex expenditure, transitioning from spending more opex than forecast to spending less opex than forecast. In 2015, only 7 out of 19 networks spent less opex than forecast. By 2020, 15 of 19 networks spent less opex than forecast.

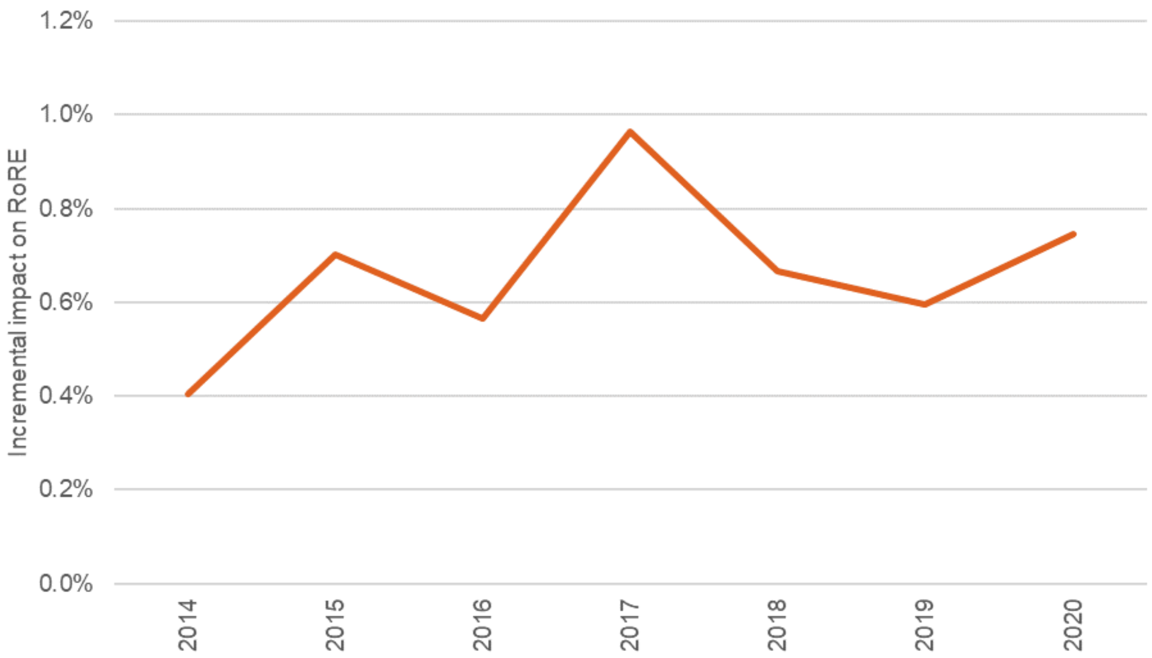
## 6.8 Impact of incentive schemes

In addition to the inherent incentives within the regulatory framework, it also includes targeted incentive schemes. These schemes are important regulatory tools designed to encourage desirable behaviours by the networks (namely to improve efficiency and reliability) which in turn will deliver better outcomes for consumers and promote achievement of the NEO.

Over 2014–20 we find that:

- Incentive schemes have on average resulted in moderate increases to network returns.
- We expect that impact is likely to grow in the coming years as more networks report CESS rewards after its initial period of operation.

**Figure 6-10 Impact of incentive schemes through time—DNSPs and TNSPs**




Source: Financial performance data, AER analysis.

Rewards or penalties generated under the incentive schemes increase or decrease network profits. This should advance the long-term interests of consumers where the value that consumers receive under the schemes exceeds the costs incurred through incentive scheme rewards.

The schemes are designed to allocate rewards and penalties in such a way that advances the long-term interests of consumers and which reflects the value consumers place on incremental improvements in reliability. Nonetheless, these schemes require an ongoing investment by consumers to encourage efficient network performance. We are committed to monitoring outcomes achieved under the schemes, and refining their design as necessary over time. To that end, we plan to undertake a review of our incentive scheme framework commencing in late-2021.

## 6.9 Impact of tax expense

Unlike interest expense, we calculate tax expense at the network level using a ‘bottom-up’ approach. Specifically, we use networks’ actual revenue and expenses to determine an estimate of actual taxable income, and multiply this by a tax rate which varies depending on the corporate structure in which the network is held.

> Over 2014 to 2020, we find that tax structure has almost no effect on returns for electricity networks, because:
>
> - Most electricity networks reported in most years that they are taxed as companies, NTER (National Tax Equivalent Regime) entities or government owned non-NTER entities.
> - Those that reported as flow-through entities retain part government ownership.
> - As a result, if we treat NTER payments as tax (or transaction equivalents for the government owned non-NTER), average tax rates are very close to our 30% benchmark.

In our tax review, we found that a major driver of past differences between forecast and actual tax was network use of immediate expensing.[55] Where used, immediate expensing allowed networks to apply tax depreciation at a faster rate than our models captured. In the short term, this had the effect of reducing tax expense compared to our forecast tax allowance. However, importantly, for a given asset value there is a fixed level of depreciation and tax depreciation networks can apply over the lives of the asset. This means that the increased tax depreciation in the past will be offset by reduced tax depreciation in the future.

Following the tax review, we updated our PTRM and RFM to incorporate immediate expensing of tax depreciation. To the extent it occurs in future, our profitability measures should reflect this through the TAB (tax asset base) depreciation and its impact on our estimate of actual tax arising from core regulated services.

## 6.10 Future development work

This initial tranche of return on regulated equity measures is the product of consultation and development over a number of years. Our view is that this measure, combined with of the other profitability measures we report, provided valuable insights for stakeholders. This includes the extent to which differences between forecast and actual revenue impact actual regulatory returns compared to our forecast returns. However, the measures are complex and have both strengths and limitations, and we anticipate ongoing development work over time. This includes:

- Reconsideration of reporting 'statutory' profit measures alongside the regulatory profit measures—in our profitability measures review we considered reporting both regulatory and statutory measures of actual network returns. In the final position paper we decided to focus initially on regulatory measures and reconsider development of statutory measures once the regulatory measures are well established. In the course of developing this report, some stakeholders have indicated ongoing interest in development of those measures and we intend to consult more widely on the advantages and disadvantages of doing so.

55 AER, Tax Review 2018—Final report, December 2018, p. 64.

- Further consideration of how best to account for imputation credits—in our profitability measures review, we set out an approach to account for the returns flowing to investors from imputation credits. It is necessary to consider imputation credits because:
  - We regulate networks under a 'post-tax' regulatory framework, where networks recover revenue to compensate them for their forecast tax expense.
  - In our imputation tax system, taxes paid at company level create franking credits which can be redeemed by eligible investors.

  To calculate the measures we have reported this year, we have accounted for the impact of actual network tax expense by capping our estimated returns from franking credits at the level of tax expense. We combine this with our market-wide estimate of the value to investors per generated imputation credit. In our view, this is consistent with a view of profits made available at the network level for distribution to their investors.

  In practice, the proportion of network owners able to redeem imputation credits may differ from our benchmark. In general, we are not seeking to capture in our measures network investors' individual tax circumstances. For example, we calculate our returns based on the proportion of debt used at the network level. An owner could separately raise debt to fund an equity share in a network and this would appear as equity in our measures. However in some cases, such as where networks are owned in flow-through structures, it is individual owners' tax circumstances which are the only relevant indicator for estimating actual tax expense arising from provision of network services. For this reason, we intend to do further work on whether it is appropriate or possible to account in our measures for investors' actual eligibility to redeem imputation credits.

# 7 Development work on network safety reporting

Network service providers are responsible for the safe operation of their networks. Safety is a factor we take into account in determining network revenue requirements, and the safe operation of networks is a part of the national electricity objective.[56] For these reasons, we have undertaken some work to consider options for adding network safety to our annual network performance reporting.

Network safety is distinct from other reporting on direct expenditure or service outputs because jurisdictional regulators have primary responsibility for monitoring and reporting on network safety compliance with licence conditions. For this report, we have undertaken a survey of publicly available reporting on network safety to better understand what information is already available. We have included references to relevant reports as an information resource for stakeholders.

To inform our thinking, we engaged with a number of jurisdictional technical and safety regulators to understand their work and reporting, and in particular to identify relevant data sources to inform how we may report on network safety. We found this input valuable and will seek to maintain ongoing engagement.

Overall, we found that there is a diverse range of information available that varies between jurisdictions. In particular, we found that there is a range of potential measures of network safety outcomes and safety related activities, and that these measures are typically used as a complement to compliance and monitoring activities by the regulators. In this sense, the material currently available does not readily allow for comparative analysis of network safety activities or outcomes.

In that context, we will include in our annual reporting a summary of available reporting and data from the jurisdictional regulators. While this does not equip us to make detailed comparisons of safety trends between jurisdictions, it draws together what information is already available into a resource for stakeholders. As new or common information becomes available from the jurisdictional safety and technical regulators we will reconsider whether it is possible to draw on it in order to expand our own reporting. In future we could explore the option of developing our own common safety data sets to enable such comparisons, however this would be a substantial and complex exercise and it is unclear how such a dataset would complement the important role of compliance and monitoring that the jurisdictional regulators already undertake.

In the remainder of this section we identify the key frameworks and concepts related to network safety and set out background and our findings on:

- Safety under the economic regulatory framework
- The jurisdictional electricity safety framework (including workplace health and safety)
- Elements of safety
- Survey of publicly available safety reporting

56 NEL, s.7.

## 7.1 Safety in the economic regulatory framework

The AER determines the forecast efficient costs used to set regulated revenues during a regulatory control period. We assess the efficiency of all capital expenditure and operating expenditure against capex and opex objectives criteria and factors.[57] We need to be satisfied that our capex and opex decisions reasonably reflects the criteria to allow a network service provider to maintain the safety of its network consistent with its legislative obligations.

Our incentive based framework sets benchmark allowances for capital and operating expenditures which allows service providers that become more efficient over time to retain part of the financial benefit from improved efficiency. Consumers also benefit when efficient costs are revealed and a lower cost benchmark is set in subsequent regulatory periods.

The incentive framework recognises that networks are best placed to make informed decisions about how to direct the allowed regulated revenue to manage the operations and maintenance of the network and associated risks. Therefore, reporting on network safety plays a role in monitoring whether networks benefiting from reductions in costs below the efficient forecast is at the expense of maintaining the safe operation of the network.

## 7.2 The electricity network safety framework

The National Energy Market (NEM) participating jurisdictions are responsible for the monitoring and compliance of network service providers' operation of the electricity networks.[58] The monitoring and compliance activity is based on legislation, licence conditions, and the setting of standards set in the relevant jurisdictions.

The safety regulatory framework recognises network service providers are best placed to operate and maintain the network to mitigate risk to a level as low as reasonable practicable (ALARP).[59] The ALARP principle aims to reduce risk where the cost of reducing risk should not be disproportionate to the benefit gained or where the solution is impracticable to implement. Safety and technical regulations require network service providers to develop a safety case that outlines a plan to document the processes and procedures used to identify and mitigate risks arising from

57 Forecast capital expenditure objectives: NER, cl. 6.5.7(a) & 6A.6.7(a); Forecast operational expenditure objectives: NER 6.5.6(a & cl.6A.6.6(a).

58 For the purposes of this report we use the term 'NEM participating jurisdictions' to include the Northern Territory, in which Power and Water Corporation is the sole monopoly operator of electricity transmission and distribution networks, alongside the interconnected network comprised of ACT, NSW, Queensland, South Australia, Tasmania and Victoria.

59 ALARP refers to reducing risk to a level that is as low as reasonably practicable. This would indicate that an operator show though reasoned and supported arguments that there are no other practicable options that could be reasonably adopted to reduce risks further Source: National Offshore Petroleum Safety and Environment Management Authority (NOPSEMA), ALARP Guidance note, 24 June 2020, available at: https://www.nopsema.gov.au/sites/default/files/documents/2021-03/A138249.pdf viewed on 18 June 2021.

the operation of network assets, such as Bushfire Mitigations Plans (BMP). These plans form part of the network service providers Electricity Network Safety Management Systems (ENSMS). [60]

Jurisdictional regulators undertake audits to identify network service provider[61] compliance with licence conditions and that ENSMS are developed to a minimum standard.[62] The standard identifies a number of criteria a network should meet when planning and preparing the ENSMS. These criteria require the demonstration that network service provider is committed to the ENSMS and specific outcomes. Part of this involves the identification and evaluation of risk control measures and treatments.

Jurisdictional safety and technical regulators complement the audit activity by obtaining reporting information from networks on certain events (notifiable) and activities related to the safe operation of the network. The data collection and analysis may identify potential areas of future audit activity. We discuss the elements of safety and related data that is publicly available in the next sections.

## 7.3 Elements of network safety

In our engagement with the jurisdictional regulators and other stakeholders, many parties emphasised that for any reporting on electricity network safety it is important to define the scope of 'safety' that is relevant for our purposes.

In our view, network performance reporting should be focussed on safety related expenditure, activities and outcomes directly related to network service providers operation of the distribution or transmission network assets. Electricity networks transport electricity from generation source to the end user. The operation of these assets carries risks that may result in consequences for the public, employees and property resulting in injury, death or damage. These collective entities risk interacting with electricity networks situated in the community and environment.[63]

The safety of electricity networks is reported against four main elements. These include:

- Safety of members of the public,
- Safety of persons working on the network,
- Protection of property (network and third party), and
- Safety risk arising from the loss of (network) supply.

60 Electricity networks are required to develop an ENSMS. The ENSMS is a document that: identifies the hazards and risks associated with the asset, describes how the safety risks are controlled, and describes the system and process in place to ensure the controls are effective and consistently applied. The concept of an ENSMS is consistent across jurisdictions and may also be referred to as 'Electricity safety management scheme', 'Safety management system', or 'Safety, reliability maintenance and technical management plan',

61 Jurisdictional regulators use the term 'Network Operator'. For convenience we will interchange the term Network Service Provider for Network Operator.

62 AS 5577 refers to the Australian Standard AS 5577 – 2013 Electricity Network Safety Management Systems.

63 NEL s.2D contains the meaning of a regulatory obligation or requirement, which includes a distribution system safety duty or transmission system safety duty.

Networks report data to jurisdictional regulators against these high level categories. It is important to note that events reported may be related to risks outside of the control of the network or characteristics of the networks' operating environment. To undertake structured performance reporting on network safety outcomes and activities, we would need to consider how this should be taken into account.

We outline the elements of safety in Table 7-1 and provide examples of actions, reported statistics and events identified during our survey of network service provider safety related information.

**Table 7-1 Elements of network safety and actions, reported statistics and events.**

| Element of safety | Actions, reported statistics and events | Events | Statistics |
|---|---|---|---|
| **Public** | Public awareness campaigns<br>Publication of safety information on network website<br>Privately owned poles, maintenance and vegetation clearance | Unauthorised access<br>Notification of shocks and tingles from public interaction with the network<br>Bushfire | Notifiable events reported:<br>Major incidents/incidents<br>Significant near misses<br>Interactions with network assets<br>Number of consumer shocks from installations caused by the network<br>Fire starts |
| **Persons working on the network** | Network employee safety and welfare programs | Employee Serious electricity work accidents (SEWA)<br>Lost time injuries (Major events including death and near misses) | Number of accidents<br>Lost time injury frequency rates |
| **Property damage: Third party and networks property** | Asset inspections and corrective actions<br>Bushfire preparedness<br>Vegetation clearance | Asset failure causing property related damage or fire<br>Vegetation and other encroachment defects<br>Significant loss of property<br>Bushfire | Number of asset and vegetation clearance inspections and corrective actions<br>Asset failures<br>Count of vegetation contact with conductions<br>Number of fire starts |
| **Safety risks from loss of supply** | | Network supply Interruptions and outage events affecting community infrastructure (such as critical infrastructure including but not limited to public lighting, traffic control systems, safe water delivery, transport and hospitals). | Number of events, date, time duration, reason<br>Minutes of lost supply |

Source: AER analysis. IPART, *Electricity Networks Reporting Manual*, May 2017.[64]

## 7.4 Survey of publicly available reporting

We undertook a review of publicly available data reported on electricity network safety. Jurisdictions reporting on network safety generally contain privatised networks such as New South Wales, South Australia and Victoria.

The jurisdictional regulators we engaged with collect data on safety related performance measures or 'KPIs'. This data collection complements their audit work by monitoring of trends in key statistics, e.g. inspections rates and failure rates that may indicate an area of increased risk to network safety.

We recognise the importance of the jurisdictional regulators role and the need to avoid duplication of regulatory reporting requirements. Our survey identified there are limitations to reporting on network safety related information where the data used to generate reports may not be available in a user friendly format for utilisation by stakeholders, may be restricted due to confidentiality concerns or privacy provisions, or is generally not available.

**Table 7-2 Summary of publicly available network safety reports and data.**

| Jurisdictional regulator | Regulated electricity network | Published reports | Summary of reported data |
|---|---|---|---|
| NSW:<br>IPART | Ausgrid[65]<br>Endeavour[66]<br>Essential[67]<br>TransGrid[68] | IPART Annual compliance report detailing compliance outcomes, events, and treatments.[69]<br><br>Networks annual report of ENSMS data on websites. | Major incidents and lower tier incidents affecting safety of public, property, workers and loss of supply<br>Control failure near misses<br>Fire starts<br>Contact incidents by person and equipment type |

64 IPART, *Electricity networks reporting manual*, May 2017. Available at: https://www.ipart.nsw.gov.au/files/sharedassets/website/shared-files/licensing-licence-dnsp-reporting-manual-201415-and-audit-guideline-december-2014/may-2017-reporting-manual-electricity-network-reporting-manual.pdf, viewed on 14 July 2021.

65 Ausgrid, *Annual ENSMS Performance Report, 30 March 2021*. Available at: https://www.ausgrid.com.au/-/media/Documents/Safety/ENSMS/ENSMS.pdf

66 Endeavour, *Annual ENSMS Performance Report 1 July 2019 – 30 June 2020*. Available at: https://www.endeavourenergy.com.au/wps/wcm/connect/5b5662d3-5434-4d80-b2d9-156a781cdd85/ENSMS+Performance+Report+FY20.pdf?MOD=AJPERES&ContentCache=NONE.

67 Essential Energy, *Safety management system annual performance report*, September 2018. Available at: https://www.essentialenergy.com.au/safety/safety-management-system.

68 TransGrid, *Electricity Network Safety Management System and Bushfire Report*, 30 October 2020. Available at: https://www.transgrid.com.au/news-views/publications/Documents/ENSMS%20Annual%20Performance%20Report%20-%202019%20-2020%20Approved%20for%20Submission.pdf.

69 IPART, *Annual compliance report – Energy network operator compliance during 2019–20*, October 2020. Available at: https://www.ipart.nsw.gov.au/files/sharedassets/website/shared-files/licensing-compliance-energy-distribution-licences-annual-compliance-report/energy-networks-annual-compliance-report-2019-20.pdf.

| | | | |
|---|---|---|---|
| | | IPART sets reporting requirement.[70] | Asset and vegetation inspections and corrective actions completed. |
| ACT:<br>Utilities Technical Regulator | EvoEnergy<br>TransGrid | UTR - Annual report detailing compliance outcomes, events, and treatments.[71]<br><br>Underlying data not tabled separately. | ENSMS compliance<br>Notifiable events and reasons<br>Pole inspections and maintenance<br>Vegetation management<br>Defective neutrals |
| Victoria:<br>Energy Safe Victoria (ESV) | AusNet (D)<br>AusNet (T)<br>CitiPower<br>Jemena Electricity<br>Powercor<br>United Energy | ESV - Annual report detailing compliance outcomes, events, and treatments.[72]<br><br>Reports on key statistics.<br><br>Underlying data not tabled separately | Regulator assessment of ENSMS compliance<br>Pole condition assessments<br>Vegetation management<br>Enforcement actions<br>Bushfire mitigation roll out<br>Investigations |
| QLD | Ergon Energy<br>Energex<br>Powerlink | EnergyQ annual report[73]<br>Powerlink annual report[74] | Community electrical safety incidents<br>Significant incident frequency rate<br>Total recordable injury frequency rate<br>Lost time injury frequency rate |
| SA:<br>Office of technical regulatory (OTR) | SAPN<br>ElectraNet | OTR - Annual report detailing compliance outcomes, events, and treatments. [75]<br><br>Includes tables of 'KPIs'. | Safety management indicators of lost time accidents and near misses<br>Shocks<br>Fire starts<br>Plant failures<br>Volumes of planned and actual maintenance activity |
| TAS | TasNetworks | TasNetworks annual report[76] | Total recordable injury frequency rate<br>Significant incidents<br>Reportable incidents |

70 IPART, *Electricity networks reporting manual – Safety management system performance measurement*, September 2020. Available at: https://www.ipart.nsw.gov.au/files/sharedassets/website/shared-files/licensing-contracting-out-electricity-network-performance-reporting-requirements/electricity-networks-reporting-manual-safety-management-system-performance-measurement-september-2020.pdf

71 Utilities Technical Regulator, *Annual compliance report 2018-19*. Available at: https://files.accesscanberra.act.gov.au/legacy/5103/Utilities-Technical-Regulation-Annual-Compliance-Report-2018-19.pdf.

72 Energy Safe Victoria, *Safety performance report on Victorian electricity networks*, October 2020. Available at: https://esv.vic.gov.au/wp-content/uploads/2020/11/2020-Safety-Performance-Report-on-Victorian-Electricity-Networks.pdf.

73 EnergyQueensland, *Annual report 2019–20*. Available at: https://www.energyq.com.au/__data/assets/pdf_file/0010/854425/2019-20-EQL-Annual-Report.pdf.

74 Powerlink, *Annual report and financial statements 2019–20*. Available at: https://www.powerlink.com.au/sites/default/files/2020-09/2019-2020%20-%20Annual%20Report%20and%20Financial%20Statements_0.pdf

75 Office of the technical regulator, *Annual Report of the Technical Regulator 2019–20*. Available at: https://energymining.sa.gov.au/energy_and_technical_regulation/office_of_the_technical_regulator.

76 TasNetworks, *Annual report 2019–20*. Available at: https://www.tasnetworks.com.au/config/getattachment/599229db-a93c-43e7-bef5-47fe1a1db193/19-20AnnualReport.pdf.

Source: AER analysis.

Note: Northern Territory and Power Water Corporation is not included. Safety related information published in PWC annual reports is limited to public awareness and employee safety and welfare campaigns.

# 8 Looking ahead to 2022

Each year, we aim to identify issues to be investigated in detail as our focus areas for future electricity network performance reports.

Over coming years, we aim to begin reporting on the role and performance of networks integrating distributed energy resources. We and other stakeholders are working across several of our work programs to identify and develop relevant indicators. We expect to incorporate these indicators in our reporting as they emerge.

We also aim to expand our reporting on measures of consumer service beyond network reliability. We have recently developed and applied the consumer service incentive scheme and will begin to collect data on the incentive measures developed by those networks and their consumers.

Beyond these longer-term goals, our work this year has identified a number of potential focus areas for 2022, including:

- Deeper analysis of recent network investment and its drivers
- Progress and impacts of network charging reform
- Trends in planned network outages
- Analysis of major outage events over time and their impacts on network expenditure
- Better understanding the impacts of unregulated network activities on financial performance indicators.

As we did in 2021, we will engage with stakeholders to identify whether we should investigate these and/or other focus areas in our 2022 report.