AusNet Transmission Group Pty Ltd

2023-27 Transmission Revenue Reset

Revenue Proposal

PUBLIC

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About AusNet Services

AusNet Services is a major energy network business that owns and operates key regulated electricity transmission and electricity and gas distribution assets located in Victoria, Australia. These assets include:

- A 6,685 kilometre electricity transmission network that services all electricity consumers across Victoria;
- An electricity distribution network delivering electricity to approximately 737,000 customer connection points in an area of more than 80,000 square kilometres of eastern Victoria; and
- A gas distribution network delivering gas to approximately 710,000 customer supply points in an area of more than 60,000 square kilometres in central and western Victoria.

AusNet Services' vision is to create energising futures by delivering value to our customers, communities and partners.

For more information visit: www.ausnetservices.com.au

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Glossary

Abbreviation	Full name
ACSR	Aluminium Conductor Steel Reinforced
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
AMS	Asset Management System
APD	Portland Aluminium Smelter
ASRR	Annual Service Revenue Requirement
BAU	Business-as-usual
BLTS	Brooklyn Terminal Station
BOM	Bureau of Meteorology
CAP	Customer Advisory Panel
CB	Circuit Breaker
CBD	Central Business District
Capex	Capital Expenditure
CESS	Capital Efficiency Sharing Scheme
CGS	Commonwealth Government Security
CT	Current Transformer
CVT	Capacitive Voltage Transformer
DAE	Deloitte Access Economics
DAPR	Distribution Annual Planning Report
DC	Direct Current
DI	Dispatch Intervals
DMIA	Demand Management Innovation Allowance

Abbreviation	Full name
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
ECA	Energy Consumers Australia
EGWWS	Electricity, Gas, Water and Waste Services
EMV	Emergency Management Victoria
EPA	Environment Protection Authority
EPDM	Ethylene Propylene Diene Monomer
ERP	Enterprise Resource Planning
ERTS	East Rowville Terminal Station
ESMS	Electricity Safety Management Scheme
ESV	Energy Safe Victoria
FAS	Fall Arrest System
FCAS	Frequency Control Ancillary Service
GIS	Gas Insulated Switchgear
GST	Goods and Services Tax
GW	Ground Wire
GWh	Gigawatt Hours
HOTS	Horsham Terminal Station
HYTS	Heywood Terminal Station
IAP2	International Association of Public Participation
ICT	Information and Communication Technology
ISP	Integrated System Plan
ISRAT	Infrastructure Security Risk Assessment Tool
IT	Information Technology
KTS	Keilor Terminal Station
MAR	Maximum Allowed Revenue

Abbreviation	Full name
MIC	Market Impact Component
MLTS	Moorabool Terminal Station
MVA	Mega Volt Amps
MWTS	Morwell Terminal Station
NCC	Network Capability Component
NCIPAP	Network Capability Incentive Parameter Action Plan
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NPV	Net Present Value
NSP	Network Service Provider
OH&S	Occupational Health and Safety
Opex	Operating and Maintenance Expenditure
OPGW	Optical Fibre Ground Wire
PCRs	Protection & Control Requirements
PPIs	Partial Performance Indicators
PTRM	Post Tax Revenue Model
RAB	Regulatory Asset Base
RCTS	Red Cliffs Terminal Station
Repex	Replacement expenditure
RERT	Reliability and Emergency Reserve Trader
RIN	Regulatory Information Notice
RIS	Renewable Integration Study
RIT-T	Regulatory Investment Test for Transmission
ROTS	Rowville Terminal Station

Abbreviation	Full name
SAIP	Smart Aerial Image Patrol
SAUR	Shared Asset Unregulated Revenues
SCADA	Supervisory Control and Data Acquisition
SHTS	Shepperton Terminal Station
SMTS	South Morang Terminal Station
STPIS	Service Target Performance Incentive Scheme
SVTS	Springvale Terminal Station
SYTS	Sydenham Terminal Station
TAB	Tax Asset Base
TNSP	Transmission Network Service Provider
TSTS	Templestowe Terminal Station
TTS	Thomastown Terminal Station
TUOS	Transmission Use of System
VAPR	Victorian Annual Planning Report
VCR	Value of Customer Reliability
VRET	Victorian Renewable Energy Target
VT	Voltage Transformer
WACC	Weighted Average Cost of Capital
WARL	Weighted Average Remaining Life
WMTS	West Melbourne Terminal Station
WVTP	Western Victorian Transmission Project
WPI	Wage Price Index
XLPE	Crossed Linked Polyethylene

Executive summary

AusNet Services owns and operates the Victorian electricity transmission network. This Revenue Proposal explains our revenue requirements for the five years from 1 April 2022.

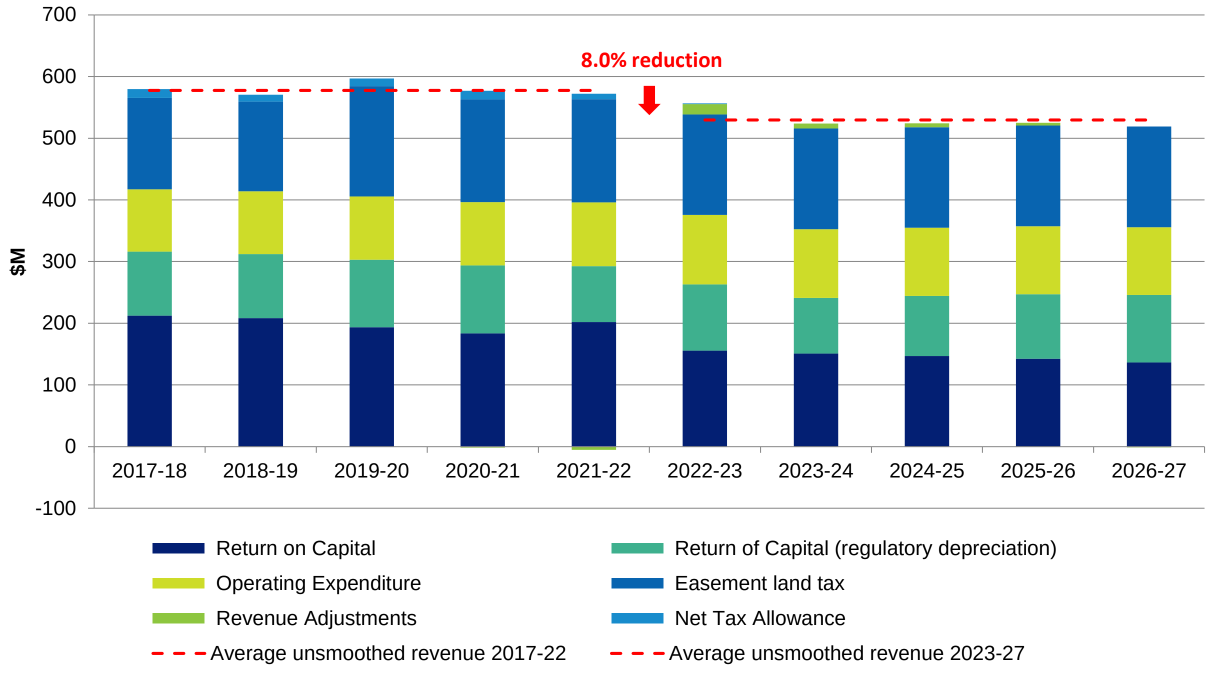
In Victoria, responsibility for planning and augmenting the transmission system is separated from ownership of the transmission assets. As the transmission network owner, we provide shared transmission services to the Australian Energy Market Operator (AEMO) and connection services to generators, distributors and large industrial customers, by maintaining and operating the network.

Our customers, including AEMO, make decisions regarding the augmentation of the transmission system, and we respond to their augmentation requests. For the purposes of this Revenue Proposal, however, we do not include these augmentation plans or their associated costs in our revenue requirements.

Our revenue forecast for the forthcoming regulatory period

Revenue is required to fund the operating and capital costs needed to maintain the reliability, security and safety of the existing transmission network. The figure below shows the composition of our revenue requirements over the current and 2023-27 regulatory periods. We present the 'unsmoothed revenue requirements' as this shows how the 'building blocks' that determine our revenue needs vary over time.

Actual, expected and forecast revenue requirement ($M, real 2021-22)



Source: AusNet Services

After accounting for our expenditure forecasts, lower interest rates and AER decisions that lower the cost of capital, the above figure shows that our average revenue requirement will be 8% lower in real terms over the 2023-27 regulatory period. As the total number of electricity customers is expected to increase, the average charge per customer will be 14% lower in real terms.[1]

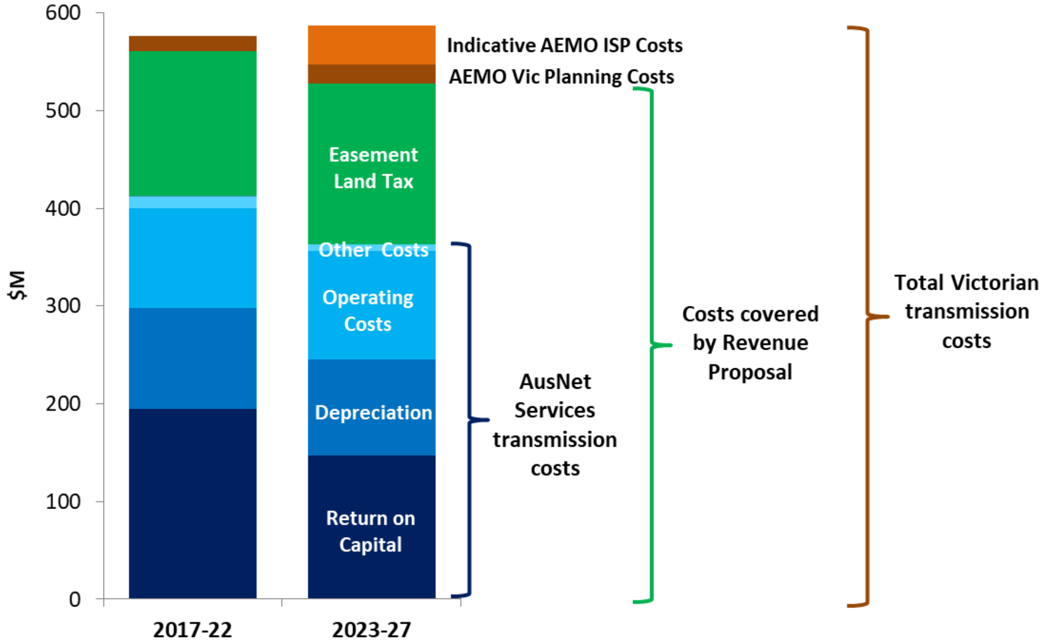
The composition of our revenue requirement highlights a number of components and inputs that are outside our direct control. In particular:

- Easement land tax and council rates[2] together make up approximately one third of our future revenue requirements. Council rates are forecast to increase over the 2023-27 period; and
- Return on capital reflects AER decisions and financial market conditions. Over the next period, this component of our revenue requirement will be lower, which delivers a saving for our customers.

While we do not have control over these factors, they form part of our revenue requirement and the transmission charges that customers pay. Our focus in this Revenue Proposal is to ensure that the costs that are within our control are managed efficiently and prudently in the long term interests of our customers.

AEMO calculates final Victorian transmission use of system charges. These charges will include costs from AEMO's Victorian planning responsibilities and any future costs associated with AEMO's 2020 Integrated System Plan (ISP). We estimate that, after these additional costs and customer growth are taken into account, the average charge per customer will fall by 8% in real terms.[3]

Total average annual Victorian transmission revenue by component ($M, real 2021-22)



Source: AusNet Services

[1] Customer numbers use historic growth rate adjusted for COVID-19 effects.

[2] Council rates are included in Operating Costs in the figure.

[3] Note: ISP costs are included for indicative purposes only because it is AEMO, not AusNet Services, that is responsible for procuring and recovering the costs of contestable ISP projects through AEMO's Victorian transmission charges. The analysis includes the costs associated with the following ISP projects: VNI Minor, Reactive Support, Victorian System Strength Shortfall, Western Victoria transmission augmentation, EnergyConnect, VNI West and Marinus Link. The analysis assumes existing cost allocation arrangements for interconnector projects.

Applying the AER's regulatory framework

Our approach in this Revenue Proposal is to adopt the AER's regulatory framework, without any material change. This includes:

- The application of the various incentive schemes that encourage efficient cost and service performance;
- The application of the AER's rate of return instrument which determines the allowed rate of return;
- A depreciation allowance that accords with the Rules requirements; and
- Pass-through arrangements that appropriately balance risks with our customers.

In each case, we have explained in this Revenue Proposal how we have applied the Rules and the AER's incentive schemes. Whilst we expect the AER will examine our Revenue Proposal during the review process, our view is that each of these elements satisfies the regulatory requirements.

Context for this review

The transformational changes across the energy sector and COVID-19 provide important context and challenges for this review. We discuss each in turn below.

Transformation to a lower carbon economy

While our role is to renew and maintain our existing transmission assets, we are cognisant of the transformation of the Victorian transmission system as Australia transitions to a lower carbon economy. The rate of this change and the challenges it creates provide important context for this review.

One feature of the growth in renewable generation is that the most productive areas in terms of sun and wind regions tend to be located in "weak" parts of the transmission network. The growth in generation capacity will coincide with the retirement of coal generation in "stronger" parts of the network.

As a result of the closure of significant baseload generation in the Latrobe Valley, the transmission pathways for Latrobe valley generation are more limited as the remaining generation is concentrated at fewer terminal stations. The availability of interconnectors is, therefore, vital to ensure Victoria and South Australia (which has also lost significant baseload generation) can access enough electricity on high demand days. The vulnerability of the system to single switched transmission elements connecting generator units and key lines has also increased.

AEMO's 2020 ISP is taking a national perspective on the need for major transmission investments to address the kind of challenges that we are experiencing in Victoria. We have worked closely with AEMO in its development of the 2020 ISP, which is seeking to deliver the lowest cost energy solution for customers. In addition, our maintenance and renewal plans described in this Revenue Proposal have been targeted to address the vulnerable areas of the network in terms of reliability and resilience.

Inflation forecasts

The AER is currently undertaking a review of the inflation forecasting methodology used in revenue determinations. A draft decision was released in September which significantly improves the accuracy of the estimate, however, under current economic conditions its application would increase approved revenues. A final decision is expected in December. During our customer and stakeholder engagement we provided indicative estimates of the revenue impact but did not incorporate it into the Revenue Proposal. After further engagement, we will incorporate the new inflation estimate into the Revised Revenue Proposal.

Impact of COVID-19

As a result of the global COVID-19 pandemic, this Revenue Proposal has been prepared and consulted on during a time of significant uncertainty.

Due to the implications of the pandemic, which began to escalate in Australia during March 2020, we postponed the release of a draft revenue proposal and sought from the AER a three-month extension to lodge our Revenue Proposal. While the AER decided to proceed along the existing review timelines, it acknowledged that adjustments to our plans to address COVID-19 impacts may be needed following lodgement of the revenue proposal.

As part of consulting on our Revenue Proposal, we explained to our customers and stakeholders how our plans may be impacted by COVID-19 and other potential changes such as the outcomes of the AER's Inflation Review. In particular, we explained that our proposed capital program may need to change to reflect new demand forecasts incorporating the effects of COVID-19, as well as changes to other key inputs to our plans that are heavily dependent on economic conditions, such as wage growth forecasts.

We will continue to engage with our customers throughout the regulatory process to seek their views on the pandemic's effects, as these become clearer. The table below sets out our post-lodgement engagement plan, which we invite our customers and stakeholders to take part in.

Post-lodgement stakeholder engagement

Timing	Method	Description
Nov – Feb 2021	Bi-lateral meetings	Recognising that the customers and stakeholders we want to engage with on our proposal are in high-demand and have limited time availability, we plan to hold a series of one-on-one sessions with customers and stakeholders scheduled at a time that suits them.
Feb 2021	Briefing session	A forum to explain the implications of new information for our plans and agree focus areas for further deep dives.
April - May 2021	Deep Dives	We will hold additional deep dive workshops to seek feedback on topics of interest to our customers and stakeholders.
June 2021	Customer Advisory Panel	To agree on how new information and insights from post-lodgement engagement activities should be reflected in our Revised Revenue Proposal.

Source: AusNet Services

Effective engagement - listening and responding to our customers

As noted above, we are committed to listening to our customers and stakeholders and reflecting their views in our Revenue Proposal.

We made a conscious decision to take a different approach to customer engagement in this review compared to our recent electricity distribution review, in which we negotiated outcomes with a specially convened Customer Forum.

Transmission businesses are less suited to a Customer Forum approach because their direct interactions with residential and business customers is more limited. Consequently, there would be fewer opportunities for the Customer Forum to translate the views of residential and business customers into our transmission plans. For this Revenue Proposal, therefore, we established a dedicated Transmission Customer Advisory Panel (CAP), which included customers and stakeholders that depend on the transmission network, in addition to consumer representatives.

The table below summarises the key points raised during our transmission engagement process and how we have responded to them.

How our Revenue Proposal aligns with our customers' preferences

Theme	Key insights from our engagement	How our plans respond in the next regulatory control period
Energy Affordability	Affordability is the key concern to our customers, particularly for vulnerable customers. For business and large users, increasing energy costs can affect the viability of their businesses.	To address affordability concerns, we took several specific actions in our plan, including: • Bearing several operating expenditure increases or 'step changes' at AusNet Services' expense; and • Including a forecast of productivity improvements in our operating expenditure forecast.
Energy Reliability	Customers generally expressed high levels of satisfaction with current reliability levels. However, for business customers, failures in reliability can lead to significant production losses and equipment damage. For this reason, many business customers place a higher value on reliable electricity supplies than residential customers. While the reliability of our network is very high, there is a desire for better communication when outages do occur.	Our expenditure forecasts have been developed to maintain the strong performance and high reliability that our customers expect of the Victorian transmission network, in line with the updated Value of Customer Reliability values released by the AER in December 2019. We are also investing to improve the communication and management of planned and unplanned outages.
Customer Relationships	Better management of strategic relationships with large customers is required.	We have established a team of dedicated customer relationship managers to serve as a contact point for directly connected large users and proactively address customer concerns and issues. Managers now hold regular meetings with their customers for this purpose.
Customer Satisfaction	While feedback recognises that customer service levels have improved in recent years, there is still considerable opportunity to improve.	We have undertaken preliminary research to better understand the experience of new generators connecting to the transmission network. We are now considering these insights and the specific actions that need to be undertaken to address them. As noted above, we are also investing to improve the communication and management of planned and unplanned outages.

Source: AusNet Services

The CAP has helped guide our engagement activities and areas of focus, meeting on six occasions over an 18-month period. With the guidance of the CAP, our customer engagement approach included:

- Two briefing sessions, which were attended by a broad range of customers and stakeholders, including: CAP members, Victorian DNSPs, consumer and industry advocates, generators and AEMO;
- Three deep dive sessions for those attending the briefing sessions. Each session focused on key elements of our operating and capital expenditure plans; and
- A series of one-on-one interviews with customers and other stakeholders to obtain feedback for inclusion in our Revenue Proposal.

We welcome the feedback which we received through this process and we will build on this engagement in the next phase of this review.

Efficient asset management and cost performance

The AER and our customers can have confidence that our asset management and governance processes underpin prudent and efficient network expenditure forecasts.

In broad terms, AusNet Services relies on the following robust planning and governance processes to drive capital expenditure forecasts that comply with the NER requirements:

- Asset management practices, which deliver an optimal balance between quality, safety, reliability and security of electricity supply with price and efficient investment for the long-term interests of consumers.
- Asset replacement planning, based on a risk-based economic evaluation, is used to ensure the efficient timing of network investment.
- Investment decision-making practices are supported by a robust project governance framework, which incorporates continuous improvement to ensure projects are delivered at lowest efficient cost.

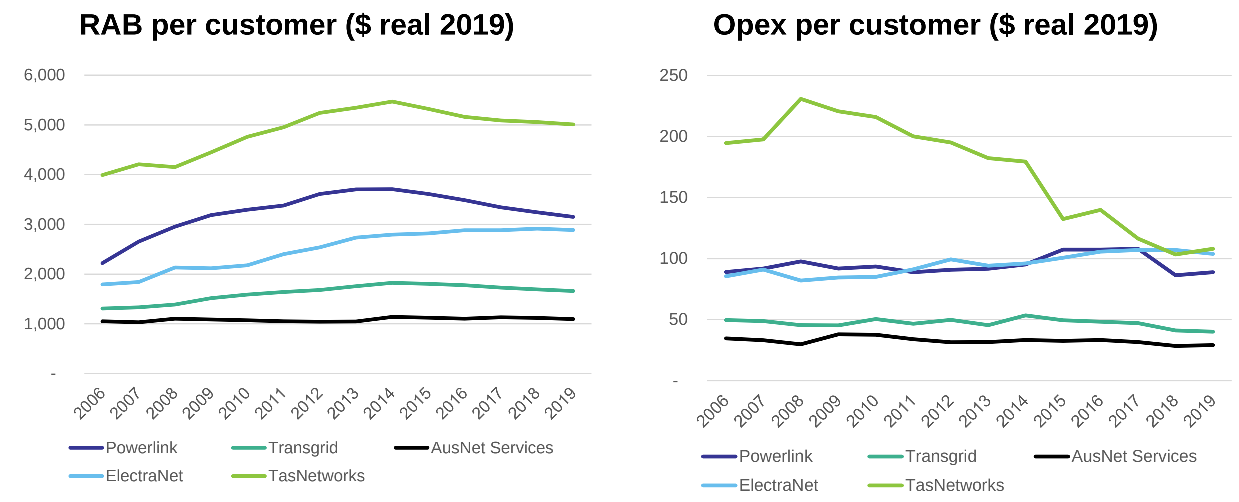
In 2014, we became the first Australian infrastructure business to achieve International Standards Organisation (ISO) 55001 accreditation for the asset management practices employed on our electricity transmission network. ISO 55001 is the internationally recognised standard for the optimised management of physical infrastructure assets.

We obtained ISO 55001 recertification in 2017, which confirmed that we continue to apply robust and transparent asset management policies, processes and procedures, and a sustainable performance framework. Effective asset management, based on condition and criticality rather than age, enables us to identify opportunities to efficiently defer the replacement of some assets. This maximises the service life of existing assets and minimises long-term costs to customers.

The efficiency of asset management and governance processes is reflected in our benchmark cost performance. The figure below shows how our total capital costs, as represented by the regulatory asset base (RAB), and operating costs per customer compare with our peers. It is reproduced using data from the AER's network performance and benchmarking reports.

The AER's analysis shows that AusNet Services' cost per customer has remained substantially below our peers. This Revenue Proposal will further reduce our revenue on a per customer basis, demonstrating an ongoing focus on efficiency.

Actual RAB and opex per customer

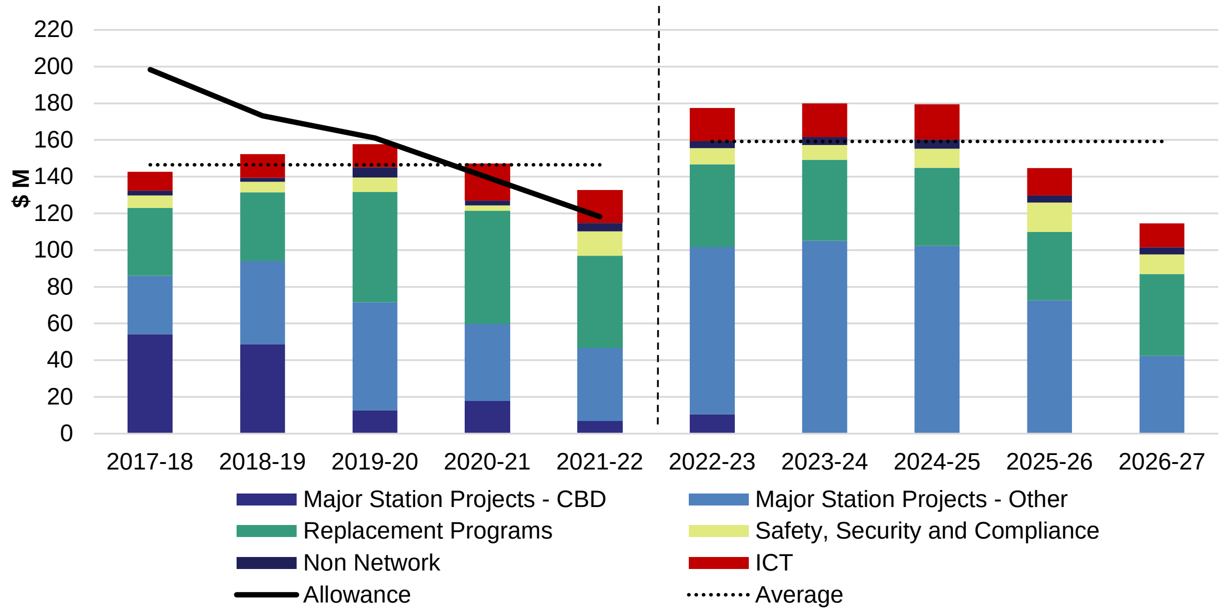


Source: AER, *Network performance report 2006-19*, September 2020; AER, Electricity transmission benchmarking report 2019, November 2019; AusNet Services analysis

Our capital expenditure forecasts

We are proposing total capex of $796 million (real 2021-22) over the forthcoming regulatory control period, which is 9% higher than our expected capex in the current period. This increase is necessary to maintain system security, reliability and safety on an ageing network.

Proposed capital expenditure ($M, real 2021-22)



Source: AusNet Services

In the current period, we delivered total capex savings of 7% ($58 million) compared to the allowance approved by the AER. Our forecast increase in the 2023-27 period is therefore closely aligned with the AER's previous allowance.

As explained below, the composition of our capex will be different in the current period (as might be expected) in order to address the specific needs facing our network. The principal change in capex requirements is the need to replace assets at several key terminal stations along the backbone of the Victorian transmission system, as well as insulator and ground-wire assets, based on their condition.

The three largest major station projects, which account for 20% of the total capital expenditure forecast, are at the critical switching stations of Keilor, Sydenham and South Morang Terminal Stations.[4] The condition-based replacement of ageing assets at these stations is vital to maintaining the reliability and security of the Victorian transmission system.

We briefly discuss each of the capex categories below following the order in the figure above.

CBD station rebuilds

During the previous and current regulatory periods, CBD station rebuilds made up around one-fifth of our total capital expenditure. This significant investment program is now nearing completion. A small component of the forecast capex for the next regulatory period relates to CBD station rebuilds, to complete the West Melbourne Terminal Station redevelopment.

Major station projects

In the previous and current regulatory periods, major stations asset replacement work has been focused on critical, aged CBD stations. The focus for the next regulatory period and beyond will shift to aged network backbone switching stations and aged rural connection stations with increasing criticality.

Our forecast Major Stations Replacement capex for the next regulatory period is 18% higher than the expected actual expenditure for the current period. This expenditure increase reflects:

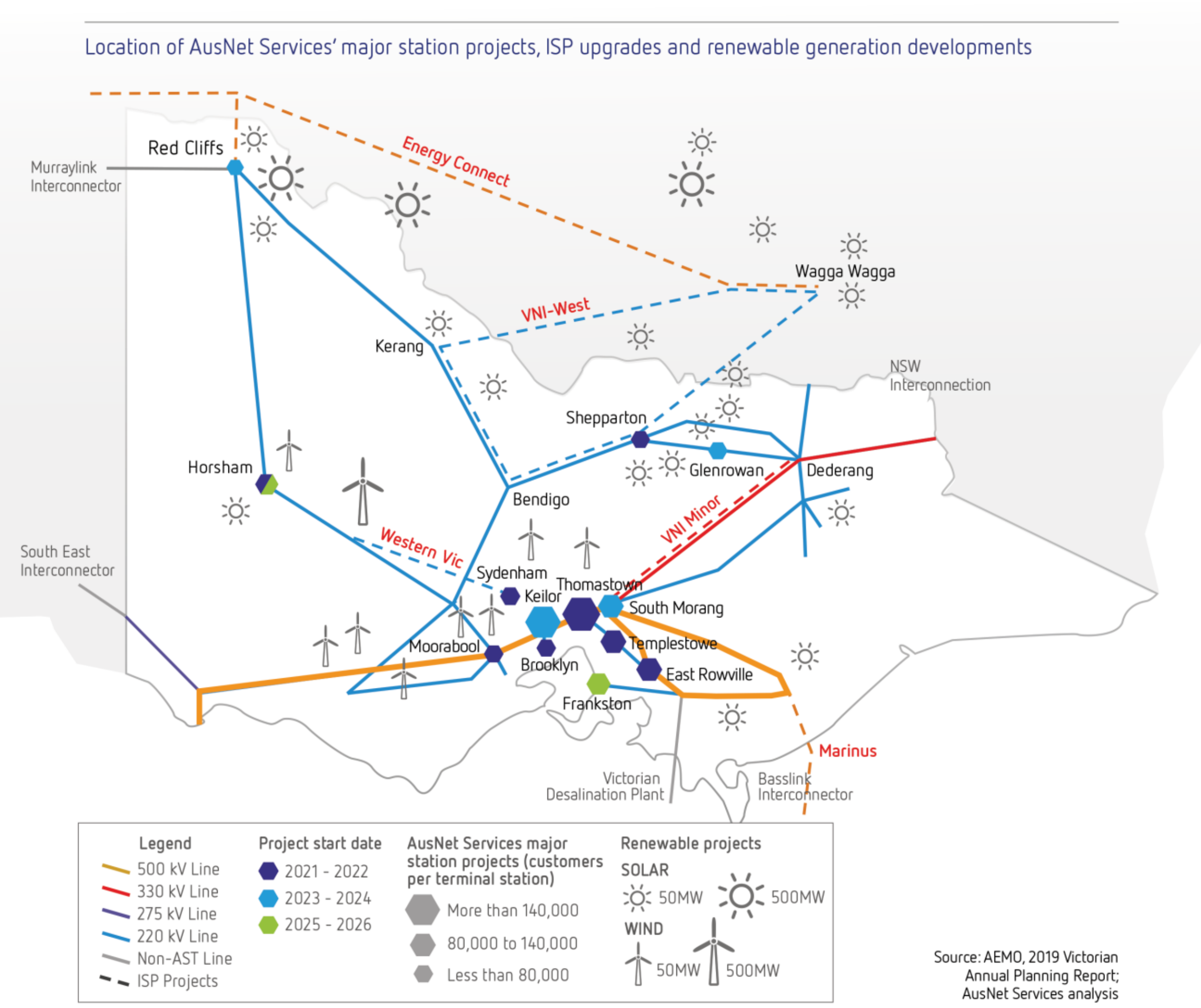
- Forecast deterioration in asset condition at a number of stations over the next period, resulting in the need to increase expenditure to efficiently address safety and reliability risks through condition-based replacement; and
- A shift in the station asset replacement away from 220 kV system assets to the replacement of more complex and expensive 500 kV assets.

As shown in the figure below, a number of our proposed major station projects interact in some way with ISP upgrade projects.

The timing, design and scope of these projects have been optimised to ensure the lowest long-term total costs to customers. This includes deferring the $33 million replacement of the F2 transformer at South Morang Terminal Station by more than five years due to the VNI-Minor upgrade, which has reduced the consequences of failure at this station.

[4] This project's scope includes replacement of the H1 transformer and 330 kV circuit breaker at South Morang Terminal Station.

Location of proposed major station replacement projects and ISP upgrades



Source: AusNet Services

Asset replacement programs

Over the previous and current regulatory periods, station assets from the 1960s have largely been replaced. Now, assets that were installed in the 1970s and 80s are displaying signs of deterioration, are approaching the end of their technical lives and, based on their condition, need to be replaced.

However, our forecast expenditure on asset replacement programs for the next regulatory period is 13% lower than the expenditure we expect to incur in the current period. This forecast reflects our risk-based approach to economic assessment of asset replacement expenditure. As already explained, asset replacement programs are assessed as being economic only when the expected cost of asset failure exceeds the cost of replacement.

Safety, Security and Compliance

Our capex forecast in this category is 47% higher than the amount of expenditure we expect to incur in the current regulatory period. While this percentage increase may appear significant, the forecast spend of $54 million is only approximately 7% of our total capex.

The increase in forecast expenditure reflects:

- The need to replace deteriorated assets that, based on the likelihood and consequence of failure, are economic to replace. This includes a $29 million program to replace a number of our insulator assets based on their condition and criticality, which is a key driver of the proposed increase on current period expected spend for this category; and
- The costs of implementing several safety-driven initiatives which are required to ensure we meet our safety obligations under the Occupational Health and Safety Regulations 2017.

Non-network capital expenditure

Our forecast for non-network capex over the next regulatory period averages approximately $4 million per annum. This represents a 17% increase on the current regulatory period, reflecting modest increases in expenditure on motor vehicle purchases and buildings.

Information and Communication Technology

Our forecast ICT expenditure for the next regulatory period is 14% higher than the expenditure we expect to incur in the current period. The key points to note in relation to ICT capex are:

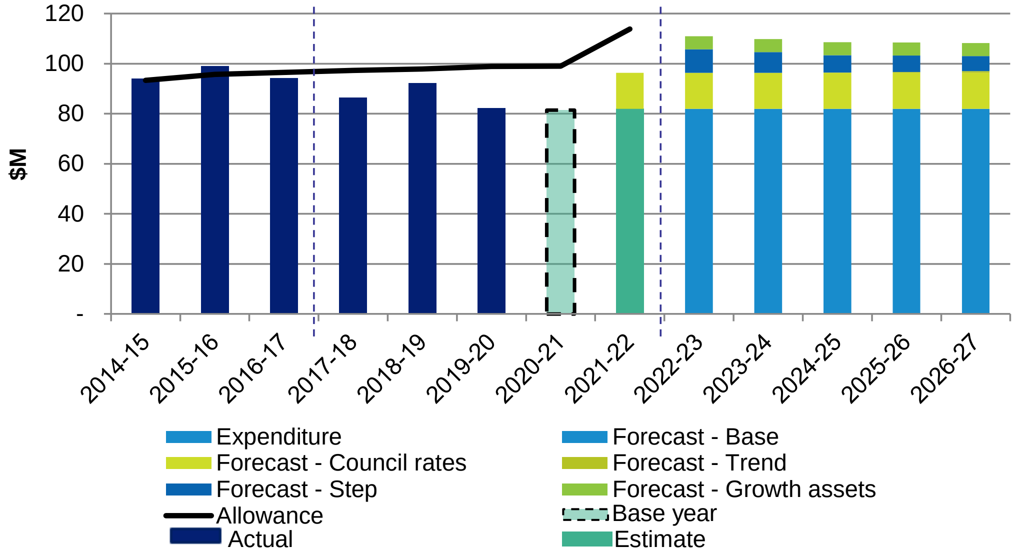
- The forecast expenditure in this category compared with previous regulatory periods is in line with long term historical levels;
- New cyber security requirements and an increasingly complex operating environment are driving the overall increase in forecast expenditure requirements; and
- ICT expenditure is cyclical in nature, reflecting the timing of major upgrades (e.g. SAP) and the lifecycle replacement of ICT systems.

Our operating expenditure forecasts

We have consulted with customers and worked with the CAP to develop an operating expenditure proposal that balances our obligation to provide safe and reliable electricity supply, comply with new regulatory requirements, and address our customers' affordability concerns.

We are proposing opex of $546 million (real 2021-22) over the forthcoming regulatory control period, excluding easement land tax and debt raising costs. Whilst our total opex is comparable with the AER's allowance in the current period, increases in council rates have a significant impact.

Proposed operating expenditure, excluding easement land tax and debt raising costs ($M, real 2021-22)



Source: AusNet Services

Note: Excludes easement land tax and debt raising costs

We are seeking further information from the Valuer-General of Victoria regarding the timing and extent of council rates increases, which were expected to occur in 2021-22 and account for $70 million of our opex forecast (shown in purple above). We will provide our stakeholders and the AER with any new information regarding these costs, either prior to the Draft Decision or in our Revised Revenue Proposal.

Our forecasting approach for operating expenditure follows the AER's established base-step-trend methodology. We have identified several areas where higher expenditure is needed to meet new regulatory obligations relating to cyber security and the environment, or deliver initiatives that will result in lower capital expenditure than would otherwise be the case.

Partly offsetting these increases, we have included a forecast of productivity improvements which has reduced our total operating expenditure forecast by $4 million over the 5-year period.

Conclusion

Our Revenue Proposal has taken account of our customers' views and focused particularly on their affordability concerns.

Whilst the composition of our capex is changing in response to the network issues, the total forecast remains closely aligned with the previous period. Our opex is expected to increase compared to the current period, driven principally by increased council rates which are not directly in our control. These upward pressures have been offset by other positive changes, most notably in relation to the cost of capital which reflect AER decisions and changing conditions in the financial markets. The net result is that our proposed total revenue requirement will be lower over the 2023-27 period.

The Proposal has been prepared in uncertain times so we welcome further feedback from our customers and stakeholders on our plans as further information becomes available and look forward to discussing them in detail with the AER.

1 Introduction

1.1 Purpose of this document

AusNet Services owns and operates Victoria's electricity transmission network. The network serves Victoria, covering an area of approximately 227,600 square kilometres and serving a population of over 5.9 million people, or more than 2.1 million households and businesses. The Victorian network is centrally located among Australia's five eastern states, and it provides important connections between South Australia, New South Wales and Tasmania.

The design and tendering for new construction of the Victorian transmission network is undertaken by the Australian Electricity Market Operator (AEMO) under arrangements that are unique to Victoria. In addition, our transmission customers have responsibility for planning their transmission connection assets. As a consequence, AusNet Services does not have responsibility for planning augmentations to the Victorian transmission system. Further information on these planning arrangements is provided in section 1.3.

This Revenue Proposal sets out the expenditure plans and revenue requirements for the Victorian electricity transmission system owned and operated by AusNet Services. It covers the five-year period from 1 April 2022 to 31 March 2027. Given the unique planning arrangements in Victoria, the scope of our Revenue Proposal is more limited than other Transmission Network Service Providers (TNSPs) because, as explained above, AusNet Services is not responsible for augmentation decision.

The remainder of this Introduction is structured as follows:

- Section 1.2 describes the scope of services covered by this Revenue Proposal and the presentation of cost information;
- Section 1.3 describes the responsibilities of different parties in relation to the Victorian transmission network;
- Section 1.4 provides an overview of AusNet Services' transmission network; and
- Section 1.5 sets out the structure of this Revenue Proposal.

1.2 Scope of services and presentation of cost information

The actual and forecast expenditure presented in this Revenue Proposal relates to the following transmission services:

- Prescribed transmission use of system services and prescribed common services, both of which are provided "in bulk" to AEMO;
- Prescribed entry (connection) services, which are provided to generators; and
- Prescribed exit (connection) services, which are provided to distributors and customers directly connected to our network.

The expenditure information contained in this Revenue Proposal is in accordance with our cost allocation methodology, as approved by the AER, and is consistent with:

- AusNet Services' capitalisation policy, which remains unchanged from the current regulatory period; and
- The application of the AER's incentive schemes that encourage cost and service efficiencies over time.

In terms of the financial data presented in this submission, it should be noted that:

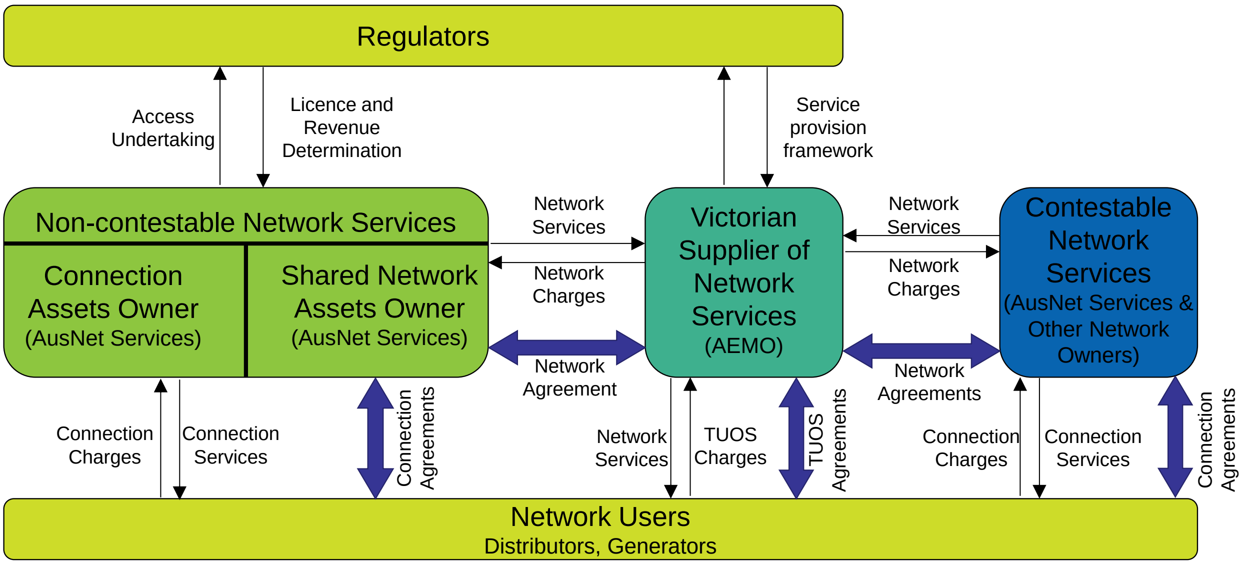
- All monetary values presented exclude GST;
- Unless stated otherwise, monetary values are presented in March 2022 dollars (shown as real 2021-22);
- Where data is presented in nominal terms, an inflation forecast of 2.25 per cent per annum has been applied; and
- Numbers in tables may not add up due to rounding.

In accordance with the National Electricity Rules (NER), we also confirm that our expenditure forecasts do not contain any costs arising from transactions with related parties.

1.3 Transmission arrangements in Victoria

In Victoria, responsibility for planning and augmenting the transmission system is separated from ownership of the transmission assets. The different roles of the industry participants in Victoria is summarised in Figure 1-1 below.

Figure 1-1: Institutional arrangements for Victorian transmission



Source: AusNet Services

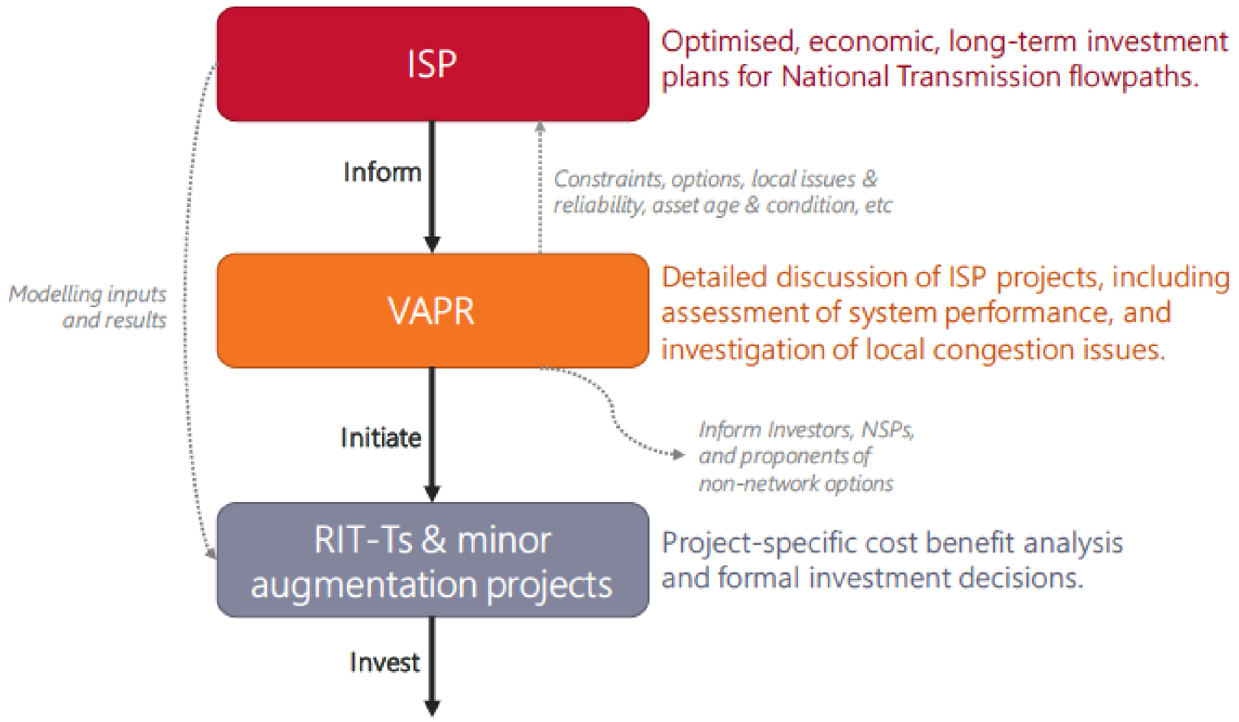
Further details about the Victorian arrangements, including the planning roles of AEMO and connected parties, are set out below.

1.3.1 Australian Energy Market Operator

AEMO is a non-profit organisation responsible for planning and procuring augmentation of the Victorian shared transmission network. AEMO also has a national transmission planning role, which requires it to publish the Integrated System Plan (ISP) every two years. The purpose of the ISP is to coordinate transmission and generation planning to provide for the efficient development of the power system over a planning horizon of at least 20 years.

In its planning role for Victoria, AEMO publishes the Victorian Annual Planning Report (VAPR) which assesses the adequacy of the Victorian transmission network to meet reliability and security needs efficiently over the next 10 years. The VAPR also provides information relating to security of supply, reliability, forecast demand, network capability, system performance, and emerging network developments that may deliver net market benefits to consumers. The relationship between the ISP, the VAPR and the investment appraisal process (the Regulatory Investment Test for Transmission or RIT-T) is shown in the figure below.

Figure 1-2: Integration of the Victorian and national planning arrangements[5]



Source: AEMO

AEMO works closely with infrastructure investors, customers and TNSPs to make decisions on when and where new transmission network infrastructure in Victoria should be built. AEMO's investment decisions are based on a cost-benefit analysis of the market impact of network limitations. Market impacts include changes to fuel costs, customer reliability, investment timing, operating and maintenance costs, network losses, ancillary service costs, market competition, and renewable energy target penalties.

Evaluating customer reliability includes considering the probability-weighted impacts from events such as:

- Single and multiple outages of transmission elements;
- Unexpectedly high levels of demand; and
- Decline in minimum demand.

AEMO seeks to deliver a level of reliability that balances investment costs with the benefits of reliable supply to customers. The value of customer reliability (VCR) measure is used to reflect the value that customers place on having a reliable electricity supply. The VCR is combined with data on the probability of an outage to estimate the energy at risk (or expected energy not supplied). The expected benefits of a potential network or non-network investment (including reductions in energy at risk) are then assessed in order to strike an economic balance between the costs of:

[5] AEMO, *Victorian Annual Planning Report 2019*, June 2019, Figure 1, p.12.

- Actions taken to ensure network capabilities are not exceeded, which may include load shedding and generation re-dispatch; and
- Providing sufficient network and non-network capability to minimise the need to limit load.

Urgent or unforeseen circumstances may necessitate augmentation of the Victorian transmission network without AEMO conducting a cost-benefit analysis. AEMO notes that these circumstances may include:[6]

- a change in government policy requiring or directing an urgent augmentation;
- actual demand is found to be significantly different to forecast; and
- natural disaster or other emergencies.

In accordance with section 50F of the NEL, AusNet Services must not augment the Victorian shared network, unless:

- AEMO authorises or directs it to carry out the augmentation; or
- AusNet Services is selected through a competitive tender conducted by AEMO to carry out the augmentation; or
- the augmentation is authorised by the NER.

AEMO determines whether an augmentation is to be classified as 'contestable', and subject to a competitive tender, even if it is an augmentation to the shared network. It is important to note that contestable network services are excluded from this Revenue Proposal, as the revenues earned from providing these services are determined by market-based competition rather than regulation.

AEMO defines a transmission network augmentation as contestable if the capital cost is reasonably expected to exceed $10 million and it can be constructed as a separate augmentation (i.e. the assets forming that augmentation are distinct and definable).[7] The Rules provide for AEMO to classify an augmentation as non-contestable if:[8]

- the delay in implementation as a contestable augmentation would unduly prejudice system security; or
- it is not economical or practicable to treat the augmentation as a contestable augmentation.

Non-contestable augmentations are 'rolled' into the regulatory asset base, as explained in section 1.3.3.

1.3.2 Connected parties

In Victoria, parties connected to the transmission network are responsible for the planning and augmentation of their connection assets.[9] Therefore, the five Victorian distribution businesses are responsible for planning and directing the augmentation of those facilities that connect their distribution systems to the shared transmission network. The Victorian distributors plan and direct the augmentation in a way that minimises costs to customers, taking into account distribution losses and losses that occur within the transmission connection facilities.

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6 AEMO, *Economic Planning Criteria – Vict*oria, October 2011, p. 4.

7 AEMO, *2014 Victorian Annual Planning Report*, June 2014, p. 86.

8 Clause 8.11.6(b) of the NER.

9 This obligation is imposed on distributors as a condition of their electricity distribution licences, issued by the Essential Services Commission.

In the event that a new connection or an augmentation of an existing connection is required, the connected parties must consult with and meet the reasonable technical requirements of AEMO, AusNet Services and other affected parties. Each year the Victorian distributors publish the Transmission Connection Planning Report, which sets out their planning criteria, and assesses the risks of lost load and options for meeting forecast demand.

In planning network asset replacements, AusNet Services consults with AEMO and the Victorian distributors in relation to future network and transmission connection augmentations, in order to ensure that asset replacement and capacity augmentation works are optimised, all opportunities for cost synergies are identified and, where possible, network augmentation is avoided using alternative solutions, including the adoption of innovative technology.

1.3.3 Augmentation of the Shared Network: Growth assets

During any regulatory control period, AEMO or a distribution business may request AusNet Services to augment the transmission network or distribution connection services. These capital expenditure works are not contestable and AusNet Services undertakes them at the direction of the responsible planner (AEMO for transmission, and the Distribution Network Service Provider (DNSP) for distribution-transmission connections). Although these assets provide prescribed transmission services, they sit outside the regulated asset base and are governed by commercial contracts until the subsequent revenue determination, when they are rolled into the regulated asset base if they satisfy the relevant criteria for inclusion. We refer to the assets that provide these services as ‘growth assets’.[10]

At each revenue reset, a number of growth assets constructed since the last revenue reset are rolled into the regulated asset base for the first time. The purpose of this process is to recognise those investments undertaken in the previous regulatory control period, and ensure that AusNet Services earns an appropriate regulated return in respect of these assets. These new additions to the regulated asset base are subject to the same rules regarding depreciation and escalation as other assets that provide prescribed transmission services. The regulatory arrangements governing the roll-in of these assets are set out in NER 11.6.21(c).

Given the roll-in process, this Revenue Proposal is concerned only with the provision of prescribed transmission services using Growth assets as at 31 December 2019, being the practical cut-off date for the roll-in of these assets. Accordingly, the expected costs and revenues associated with the provision of any prescribed services commissioned after 31 December 2019 are excluded from the revenue cap for the forthcoming regulatory control period.

Figure 1-3 shows the different regulatory approaches that apply to replacement capital expenditure and growth assets. Specifically, AusNet Services’ forecast replacement capital expenditure is included in the regulatory asset base and remunerated through the revenue cap. As explained above, however, growth assets are remunerated through commercial contracts initially and then can be rolled into the regulated asset base at the next revenue reset.

[10] Previously referred to as ‘Group 3 Assets’.

Figure 1-3: Replacement and Growth assets

Replacement	Growth assets
• Replacement capex on AusNet Services' existing assets which provide prescribed services • Forecast replacement capex included in the forecast Regulated Asset Base	• Augmentation and connection capex for prescribed services (not negotiated or contestable) as required by AEMO or distribution businesses • No forecast Growth assets included in the forecast Regulated Asset Base

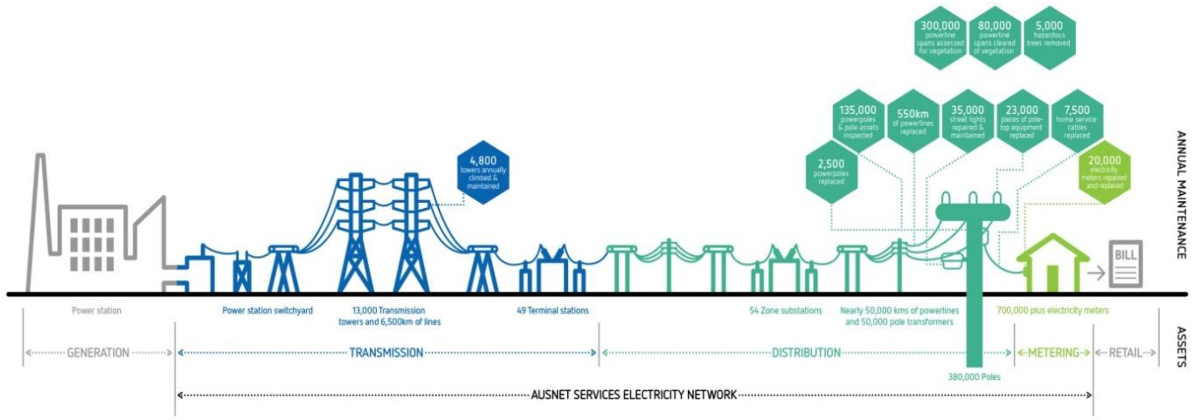
Source: AusNet Services

The periodic roll-in of growth assets increases the volume of regulated assets. As a consequence, the operating expenditure allowance must increase to manage the higher volume of assets that must be inspected, condition assessed and maintained. Details of AusNet Services' operating expenditure requirements are set out in Chapter 5.

1.4 Overview of AusNet Services' transmission system

AusNet Services' transmission system operates at 500 kV, 330 kV, 275 kV, 220 kV and 66 kV, and generally includes those assets between the 'point of connection' with generators and distribution companies, as illustrated in Figure 1-4.

Figure 1-4: Facilities and assets in the Victorian electricity system



Source: AusNet Services

AusNet Services' electricity transmission network includes more than 6,500 kilometres of transmission lines that transport electricity from power stations to electricity distributors and large customers. The network is centrally located among Australia's five eastern states that form the

NEM, and provides key connections between South Australia, New South Wales and Tasmania's electricity transmission networks. The NEM interconnections on AusNet Services' transmission network include:

- two 330 kV lines from Dederang Terminal Station, to the Murray Switching Station (NSW);
- one 330 kV line from Wodonga Terminal Station to Jindera (NSW);
- one 220 kV line from Red Cliffs Terminal Station to Buronga (NSW);
- two 275 kV lines from Heywood Terminal Station to South East Substation (SA);
- one 220 kV circuit from Red Cliffs Terminal Station to Berri (SA); and
- one 500 kV circuit from Loy Yang Power Station to the 400 kV HVDC circuit between Loy Yang and Bell Bay (Tas).

The transmission network consists of a 500kV backbone, running from the Latrobe Valley, through Melbourne and across south-west Victoria to Heywood. The backbone serves the major load centres and is reinforced by:

- a 220 kV ring around Melbourne supplying 220 kV/66 kV/22 kV terminal stations;
- inner and outer rings of 220 kV/66 kV/22 kV terminal stations in country Victoria supplying the regional centres; and
- interconnections with New South Wales, South Australia and Tasmania.

The transmission system location, configuration and voltages are illustrated in Figure 1-5 below.

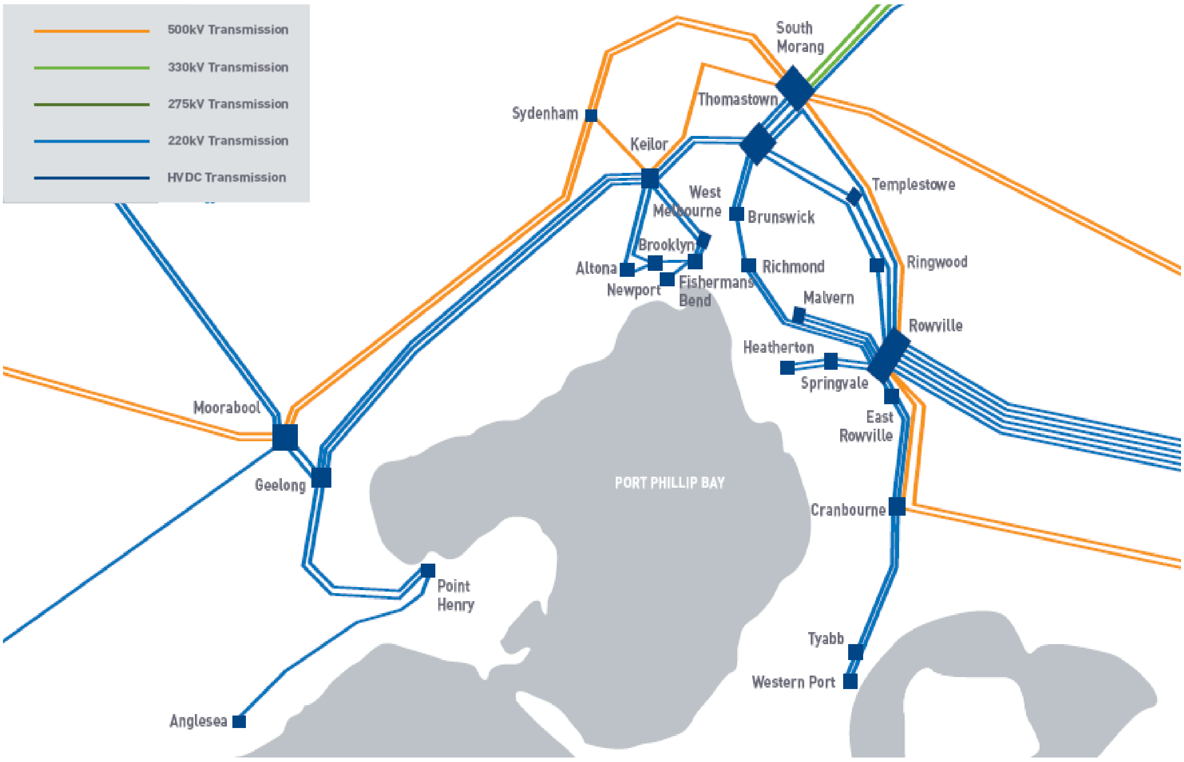
Figure 1-5: Victorian electricity transmission system

Source: AusNet Services Asset Management Strategy

Metropolitan Melbourne is served by 500 kV and 220 kV networks which receive power from major coal and gas generators in the Latrobe Valley, the Victorian hydro-electric power stations, the interstate links and, increasingly, from the large scale renewable generators connecting throughout regional Victoria.

The configuration of the metropolitan transmission system is shown in Figure 1-6.

Figure 1-6: Metropolitan Melbourne electricity transmission system



Source: AusNet Services

1.5 Structure of this Revenue Proposal

The remainder of this document is structured as follows:

- Chapter 2 provides context for this Revenue Proposal by describing AusNet Services' operating environment and its key challenges for the forthcoming regulatory control period.
- Chapter 3 provides an overview of the customer engagement we have undertaken to better understand the needs and preferences of our customers, and to inform this Revenue Proposal.
- Chapters 4 and 5 explain AusNet Services' capital and operating expenditure proposals, respectively.
- Chapter 6 presents information relating to shared assets.
- Chapter 7 shows the derivation of the efficiency incentive payments that result from the operation of the Efficiency Benefit Sharing Scheme (EBSS) and the Capital Expenditure Sharing Scheme (CESS) during the current regulatory control period. The chapter also presents information on the service performance and efficiency incentive schemes that will apply over the forthcoming regulatory control period.
- Chapter 8 provides an overview of the calculations underpinning the opening regulatory asset base (RAB) at the start of the next regulatory control period, and the forecast RAB for that period.

- Chapter 9 sets out the depreciation allowance for the forthcoming regulatory control period.
- Chapter 10 outlines AusNet Services' proposed return on capital and gamma.
- Chapter 11 explains AusNet Services' proposed tax allowance.
- Chapter 12 details AusNet Services' proposed cost pass-through arrangements.
- Chapter 13 presents AusNet Services' total revenue requirement for the forthcoming regulatory control period and the resulting average transmission charges.
- Chapter 14 sets out AusNet Services' proposed pricing methodology for the forthcoming regulatory control period.
- Chapter 15 describes and explains AusNet Services' proposed negotiating framework for the forthcoming regulatory control period.

1.6 Supporting documents

The following supporting documents are relevant to this chapter:

- Appendix 1A – Cost Allocation Methodology.
- Appendix 1B – Related Party Arrangements.

2 Transmission services environment

2.1 Introduction and overview

This chapter describes the environment for electricity transmission services in Victoria and the implications for AusNet Services in its role as principal network manager and operator. The national energy market transition toward a renewable generation mix is changing at unprecedented speed. Power flows on the transmission network and local operating conditions are changing as a result of the relocation of generation sources and changes in their characteristics. There are important considerations for transmission network management arising from these changes to maintain a safe, reliable and secure electricity supply.

The chapter is structured as follows:

- Section 2.2 outlines emerging energy market trends relevant to the transmission sector;
- Section 2.3 sets out our recent achievements, a number of which build on initiatives in earlier regulatory periods;
- Section 2.4 describe the ongoing challenges facing the business, which include an ageing asset base and the challenges from the closures of large generating stations;
- Section 2.5 provides an overview of our asset management practices and the regulatory, legal and technical obligations that must comply with to ensure that we continue to provide safe and reliable transmission services; and
- Section 2.6 lists the supporting documents provided that relate to this chapter.

2.2 Responding to emerging energy trends

2.2.1 The renewable energy transition

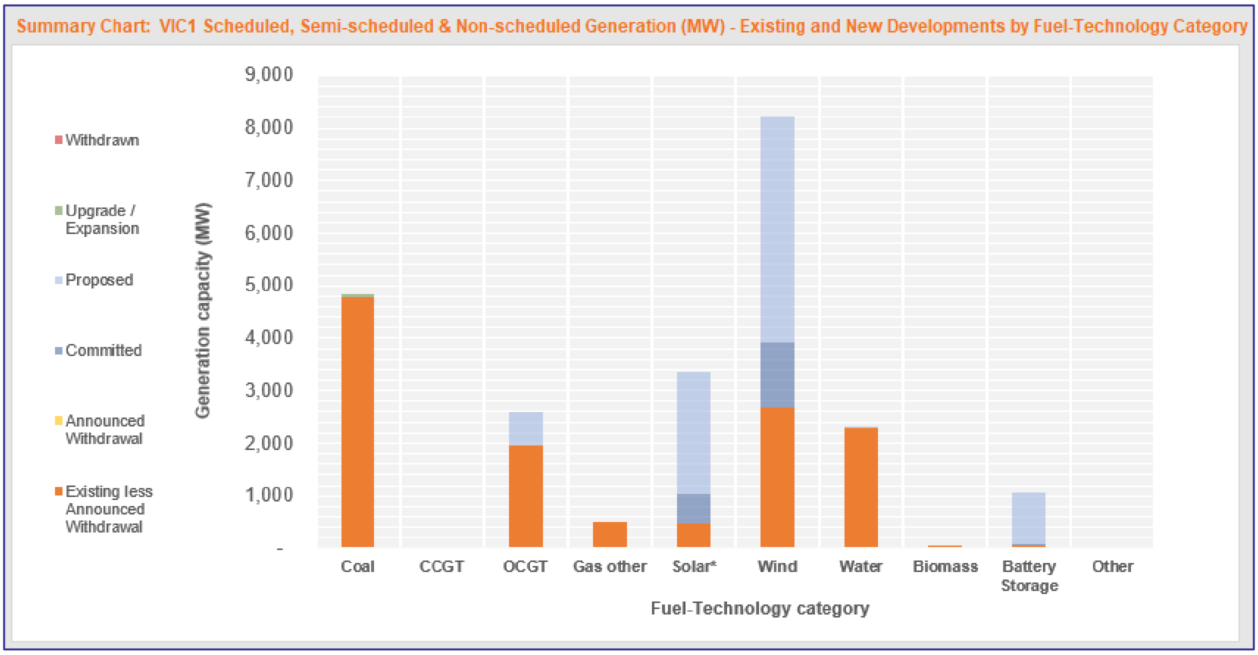
Renewable energy targets, reducing technology costs and the retirement of aged coal generation plant are radically changing the generation mix in Victoria and the wider NEM. The Victorian government has set renewable energy targets of 25% by 2020, 40% by 2025 and 50% by 2030.[11] Across the NEM, variable renewable generation is expected to grow to 16 GW within 2 years, with 8 GW of this located in Victoria. By 2040, a further 31 GW is forecast to be needed in AEMO's Integrated System Plan central scenario, and 50GW in the fast change scenario, with 7 GW of this connected to the network in Victoria.[12]

As can be observed from the figure below, existing renewable generation capacity (including hydro) is now comparable with traditional coal fired generation, whilst proposed projects indicate that the capacity of coal generation will be rapidly overtaken. Significant amounts of the new generation fleet is non-synchronous (inverter connected), including wind and photo-voltaic generation, with battery storage based generation also growing.

[11] DELWP website https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets.

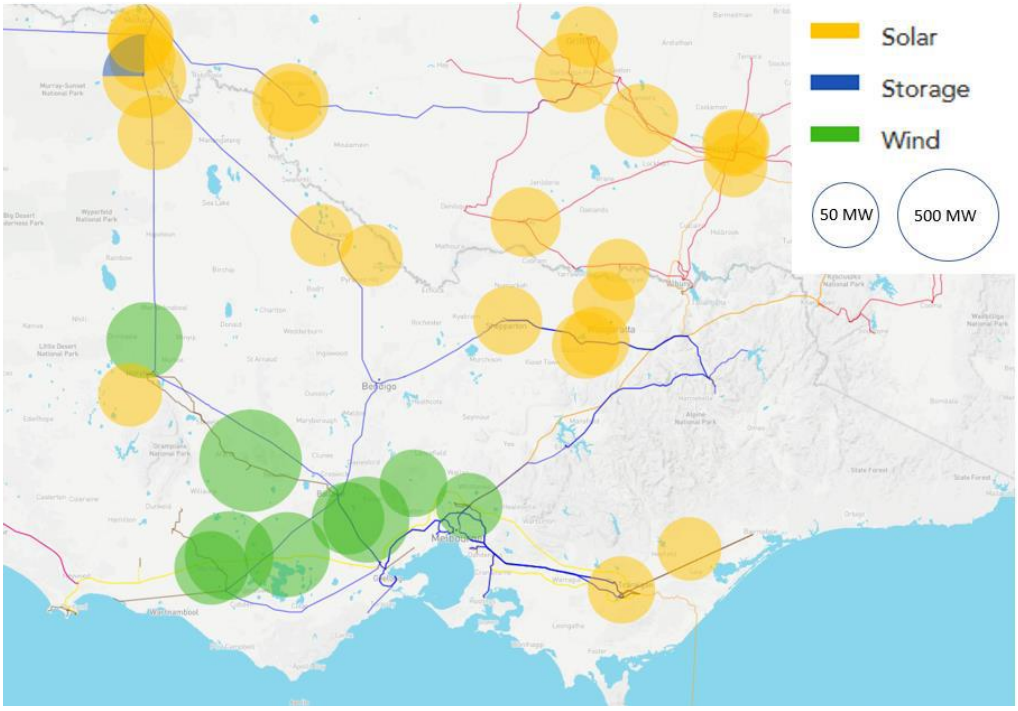
[12] AEMO, *2020 Integrated System Plan*, pages 43-44, 30 July 2020.

Figure 2-1: Victorian generating capacity - existing and new developments by fuel technology category[13]



The figure below indicates the high level of interest for new investment in developing additional renewable generation in Victoria.

Figure 2-2: Map of generator connection applications[14]



[13] AEMO, *NEM Generation Information July 2020 V2*, 29 July 2020.

[14] AEMO, *Draft 2020 ISP*, Figure 14, page 63.

The Victorian regional transmission network was designed to bring electricity supply to local communities, and not in anticipation of serving major energy export hubs. Whilst the network is now supporting newly established non-synchronous generation its capability is limited, such that the transmission network must transform to accommodate the accelerating growth in renewable generation connections. The transition to an energy system with significant deployment of these generation technologies has implications not just for network capacity, but for real time operation of the system, leading to new consideration of how elements of the operating envelope are managed, including frequency control, voltage management, system strength, voltage oscillations, frequency control and inertia.

Victoria has not undertaken any major transmission line development for 30 years. In fact, AusNet Services' asset replacement program, which is necessary to ensure on-going reliability from the network, has been the most significant category of capital expenditure.

However, the renewables transformation is altering this situation. Augmentation of the Victorian network is essential to enable new generation to connect and be transported to load centres. For example, AEMO (in its Victorian transmission planner / provider role) established the Western Victoria Transmission Project, and contracted with AusNet Services for the major transmission upgrade. The works include a new North Ballarat terminal station and long-distance high voltage transmission lines between Bulgana and Sydenham terminal stations. The project is staged over several years, with the final component expected to be in operation by 2025.[15]

2.2.2 The Integrated System Plan

Early in 2020, the Energy Security Board concluded development of a process for the 2 yearly preparation of the Integrated System Plan (ISP). The ISP is a roadmap for development of the NEM-wide power system over a 20 year period. Amongst other things, it ranks transmission needs, with those most urgent categorised as actionable ISP projects, triggering a regulatory investment test. AEMO prepares the ISP using extensive modelling, stakeholder engagement, and in depth consultation with the TNSPs to take into account and align with regional transmission plans.

With increased focus on systemwide planning to integrate the new energy sources and address rising security risks, there is the opportunity for Victorian planning to establish an aligned vision and roadmap. Preparation for future network augmentation needs could be initiated to ensure timely new investment is commissioned, in particular through streamlining advance works, such as obtaining necessary easements.

Whilst the augmentation currently proposed in Victorian transmission development plans will reduce the most urgent congestion, the expected significant future investment in renewables will continue to put pressure on network capability and system security. An example of this is the deterioration in system strength at locations remote from concentrated synchronous generating plant, where new non-synchronous generation often connects. Changing characteristics of the power system can affect the reliable and secure connection of local generation, and it has implications for the performance of the transmission network. The operation of network protection systems is sensitive to system strength parameters and this is a consideration in determining minimum system strength.

Deteriorating system strength has become an important consideration when identifying available windows to take transmission assets out of service for critical maintenance. Removing network

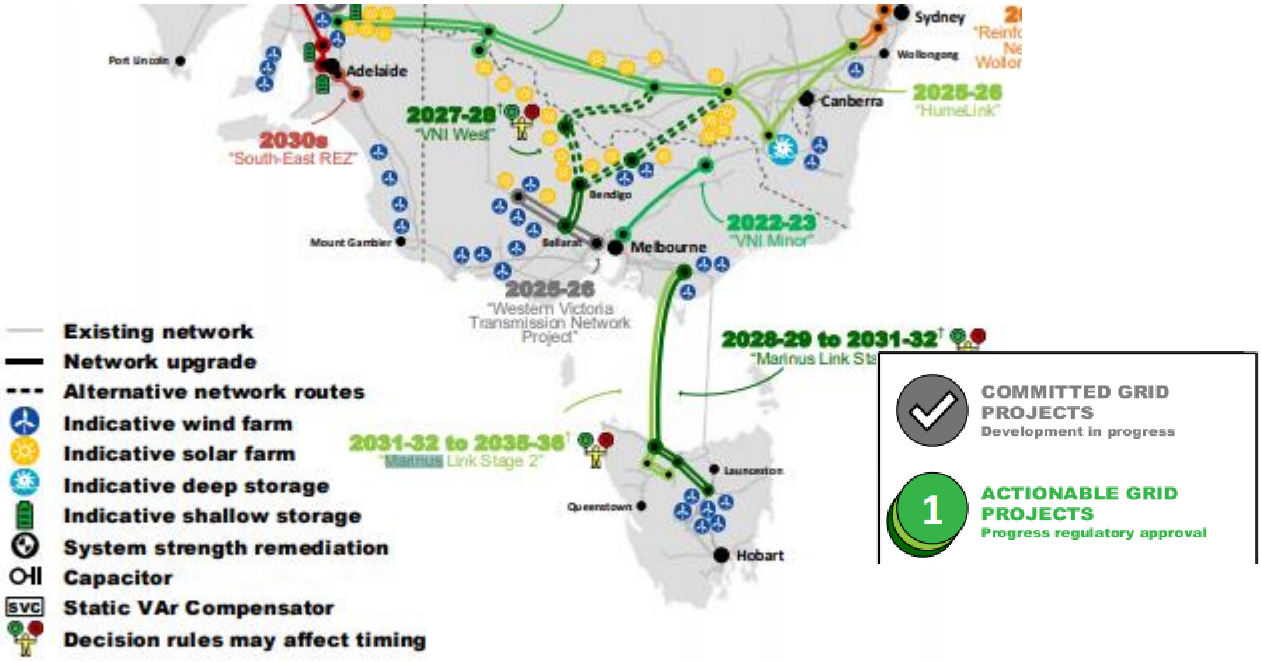
[15] AEMO website https://aemo.com.au/en/initiatives/major-programs/western-victorian-regulatory-investment-test-for-transmission/procurement.

elements typically increases network impedance and deteriorates system strength during the period of the outage, with potential operational impact for the power system. The challenge of obtaining outages for maintenance is discussed further in section 2.4.

2.2.3 ISP optimised development path for Victoria

The 2020 ISP was released in July 2020. Developments in the plan centred around Victoria are shown in Figure 2-3.

Figure 2-3: ISP Developments in South East Australia



Source: AEMO

The key projects that are either committed or planned for Victoria include:[16]

- **Western Victoria transmission network project**
  A committed project expected in 2025-26 to add transmission capacity to the western and north-western parts of Victoria.
- **VNI minor**
  A minor upgrade to the existing Victoria – New South Wales interconnector. This upgrade is expected to be delivered in 2022-23.
- **VNI West**
  A new interconnector between Victoria and New South Wales that may be required by 2027-28, but in most scenarios has optimal timing in the mid-2030s. This project would provide insurance against an early closure of the Yallourn Power Station and support the proposed Snowy 2.0 scheme.
- **Marinus Link**

  Marinus Link provides additional interconnection between Tasmania and Victoria, providing access to large-scale storage in Tasmania, with benefits including more efficient generation sharing between the states. Optimal timing ranges from 2028-29 to 2035-36.

[16] AEMO, *Draft 2020 ISP*, p.68.

Uncertainties in power system development plans place tremendous importance on the capability and reliability of AusNet Services' established transmission network to meet the needs of Victorian consumers and to support the renewables investment ambitions of the Victorian Government's VRET scheme.

AEMO, in its role as NEM power system operator, is leading investigative work to improve generator connection capability in the West Murray area of NSW and Victoria, consistent with secure operation requirements.[17] Initially, generation in the region was curtailed, as unsatisfactory voltage fluctuations threatened power system security. AEMO notes two future interconnector developments (VNI minor and VNI West) will deliver critical benefits for this area.

In April 2020, AEMO released a Stage 1 Report on its on-going multi-year Renewable Integration Study (RIS).[18] In it, AEMO reports on its investigation of the likely challenges over the next five years in maintaining power system security while operating the resource mix with very high instantaneous penetrations of wind and solar generation.

The study concludes that higher penetrations of variable renewable generation could be accommodated if the actions recommended in the report are taken. The actions largely comprise specified further work by AEMO in the development of process, tools and training to support secure operation; regulatory and market reforms to support secure operation; and investigations to better understand secure and more efficient operation.[19]

2.2.4 2019 Victorian Annual Planning Report

In its 2019 Victorian Annual Planning Report (VAPR), AEMO also recognised that the energy transition has implications for transmission network asset management. AEMO noted that it works closely with AusNet Services to assess the need and economic justification for the replacement, refurbishment, derating, or retirement of assets that are approaching end-of-life. AEMO also notes that in preparing the 2019 VAPR it has included a sensitivity analysis on the potential asset replacement impact of future generation plant withdrawals in the Latrobe Valley.[20]

Good asset management practices, with the objective of ensuring enduring reliability, system security and safe operation of AusNet Services' transmission network, have never been more important than in this emerging phase of transition. Planned augmentations cannot provide benefits without the continued good reliability performance of the established network. This requires close monitoring by AusNet Services to identify optimal and practical opportunities to replace critical assets that are aged and/or in poor condition. Integration of renewal and network development investments is also an important consideration. For these reasons joint planning which draws together AEMO's Victorian transmission planning accountability and AusNet Services' asset management priorities is an important process in achieving efficient overall outcomes.

This Revenue Proposal sets out AusNet Services' priority asset management requirements for the network to continue to provide safe and reliable services.

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[17] AEMO, *Transforming Australia's Energy System*, 10 February 2020 https://aemo.com.au/-/media/files/electricity/nem/network_connections/west-murray/transforming-australias-energy-system--west-murray.pdf?la=en&hash=ED13D8375B1E37626EEAFC86C59622EE.

[18] AEMO, *Renewable Integration Study, Stage 1 Report*, April 2020 https://aemo.com.au/-/media/files/major-publications/ris/2020/renewable-integration-study-stage-1.pdf?la=en&hash=BEF358122FD1FAD93C9511F1DD8A15F2.

[19] ibid, Figure 2, page 12.

[20] AEMO, *VAPR* https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2019/victorian-annual-planning-report-2019.pdf?la=en&hash=0AF8BABAA9315FB0A2D9B82E42D37C0C.

2.2.5 Effects of climate change

Australia is experiencing increasingly hot summers. The Bureau of Meteorology's (BOM) Annual Climate Statement[21] for 2019 reveals that the mean temperature for the 10 years from 2010 was the highest on record, and that all years since 2013 have been amongst the ten warmest on record. 2019 itself was Australia's warmest year on record. The 2019-2020 summer experienced severe bushfires across many regions of Australia. The BOM report notes that widespread severe fire weather was experienced throughout the year, and that the national annual accumulated Forest Fire Danger Index was the highest since 1950, when national records began.

This trend in weather patterns has implications for the electricity system, including the operation of the transmission network. The influences can be seen from AEMO's 2019-20 NEM Summer Operations Review Report[22] which notes the vulnerability of key transmission lines to fire impacts and extreme weather events. The report states:

> *Australia's physical gas and electricity infrastructure is being increasingly challenged by extreme and high heat and fire periods. The need to harden these assets to more extreme climatic conditions and consider opportunities to enhance the inherent resilience of the NEM when planning and delivering either new projects or replacing existing infrastructure will be a necessary element of future NEM planning*.[23]

Having regard to the vulnerability of transmission lines to fire impacts, the report observes that:

> *This highlights the need to integrate resilience measures into the planning, routing, design, and assessment of transmission projects and upgrades, to:*
>
> *– Increase thermal operating limits.*
>
> *– Introduce more fire-resistant construction.*
>
> *– Enhance interconnection between major load centres*.[24]

Whilst electricity demand increases with higher ambient temperatures being experienced, and there is accordingly greater dependence on the network, the thermal transfer capability of transmission assets is impacted under high ambient temperature conditions. AEMO's dispatch system automatically includes this variability in constraint equation calculations.

The increasingly tight supply/demand balance and reduced proportion of synchronous generating plant on the power system has led to a significant increase in the number of market interventions by AEMO. Figure 2-4 shows the increase that has occurred over the recent 10 year period to 2018.

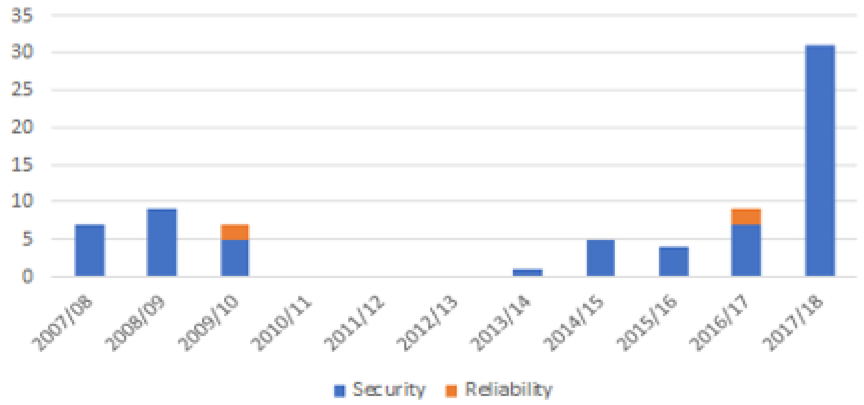
[21] Bureau of Meteorology, *Annual Climate Statement 2019*, 9 January 2020 (http://www.bom.gov.au/climate/current/annual/aus/2019/).

[22] https://aemo.com.au/-/media/files/electricity/nem/system-operations/summer-operations/2019-20/summer-2019-20-nem-operations-review.pdf?la=en.

[23] ibid, page 3.

[24] ibid, page 3.

Figure 2-4: AEMO market interventions



Source: AEMO

More recently, AEMO has used the Reliability and Emergency Reserve Trader (RERT) intervention mechanism to contract off-market emergency reserves. AEMO's 2019-20 NEM Summer Operations Review Report notes that it:

> *observed a significant increase in NEM reliability risk following the retirement of a number of baseload generators (including Hazelwood, Northern, Munmorah, Wallerawang, and Anglesea power stations).*[25]

Over the 2019-20 summer AEMO activated RERT services on 4 occasions, 2 of which were for RERT services in Victoria.

The Australian Academy of Science observes an expectation of rainfall extremes becoming more frequent and intense with increasing atmospheric temperatures.[26] As well as adapting to potentially drier and hotter environments, networks will therefore need to monitor and adapt to the occurrence of more extreme storm and rainfall events.

2.2.6 Impact of COVID-19 pandemic on energy usage

The COVID-19 pandemic has had significant short-term effects on the Australian society and economy. So far, Victoria has been hit harder than most. Some sectors of the economy have been almost completely shut down, with the tourism and entertainment sectors particularly hard hit. Regional, interstate and international travel has slowed significantly. Current Government forecasts suggest unemployment levels will peak in the September quarter and that the economy will begin recovery from an estimated 11% fall in monthly Gross State Product in 2021.[27]

Therefore, long term economic effects are still highly uncertain. Various Government and private organisations have explored possible future scenarios. Generally, these vary widely depending on assumptions about eradicating the virus and the development of a vaccine.[28] Typically, studies suggest that some sectors, such as communications and information technology will grow strongly

[25] ibid, page 43.

[26] Australian Academy of Science website, https://www.science.org.au/learning/general-audience/science-climate-change/5-how-are-extreme-events-changing.

[27] Department of Treasury and Finance, *Victorian Economic Update*, July 2020, https://www.dtf.vic.gov.au/sites/default/files/document/Victorian%20Economic%20Update%20-%20July%202020.pdf.

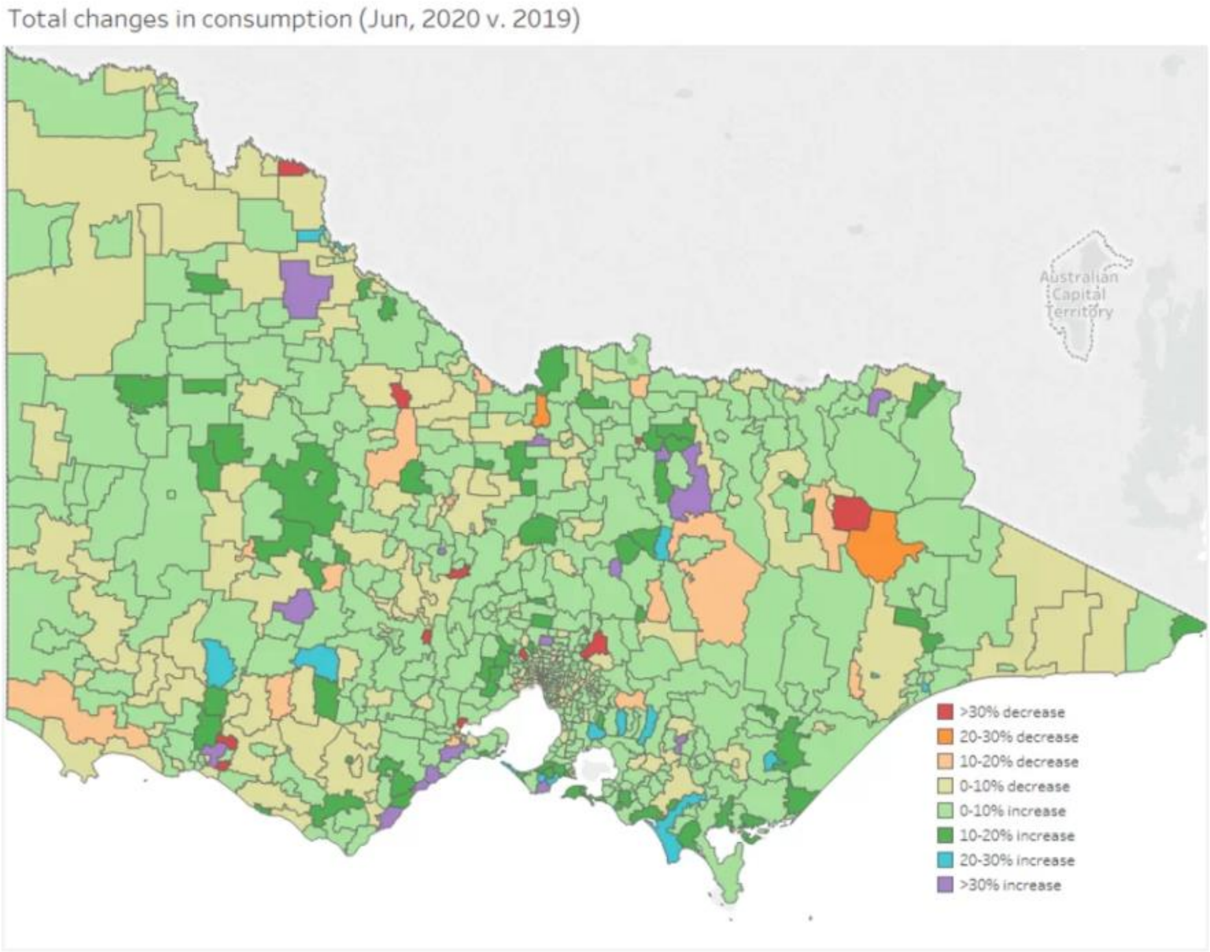
[28] For example, City of Melbourne, *Economic Impacts of COVID-19 on the City of Melbourne, Final Report*, 20 August 2020.

in the altered environment under all scenarios, whilst the activity in other sectors, such as tourism and tertiary education, will take a number of years to recover in some scenarios.

Due to this uncertainty, this Revenue Proposal has not attempted to incorporate the long-term effects of the COVID-19 pandemic. By waiting until September 2021 when the Revised Revenue Proposal is due to be submitted, AusNet Services expects to be able to gather more accurate information and undertake meaningful consultation in order to submit improved expenditure forecasts to the AER.

Nonetheless, for the Victorian electricity sector, the smart meter fleet has enabled network service providers to obtain reliable evidence of actual electricity usage during the lockdown period in Victoria. The data reveals that whilst there was a reduction in business consumption, this has been offset by an increase in residential demand, such that overall electricity demand has remained relatively stable. Figure 2-5 compares electricity usage during May 2020 with the same period in 2019.

Figure 2-5: Comparative electricity usage – May 2020 vs May 2019



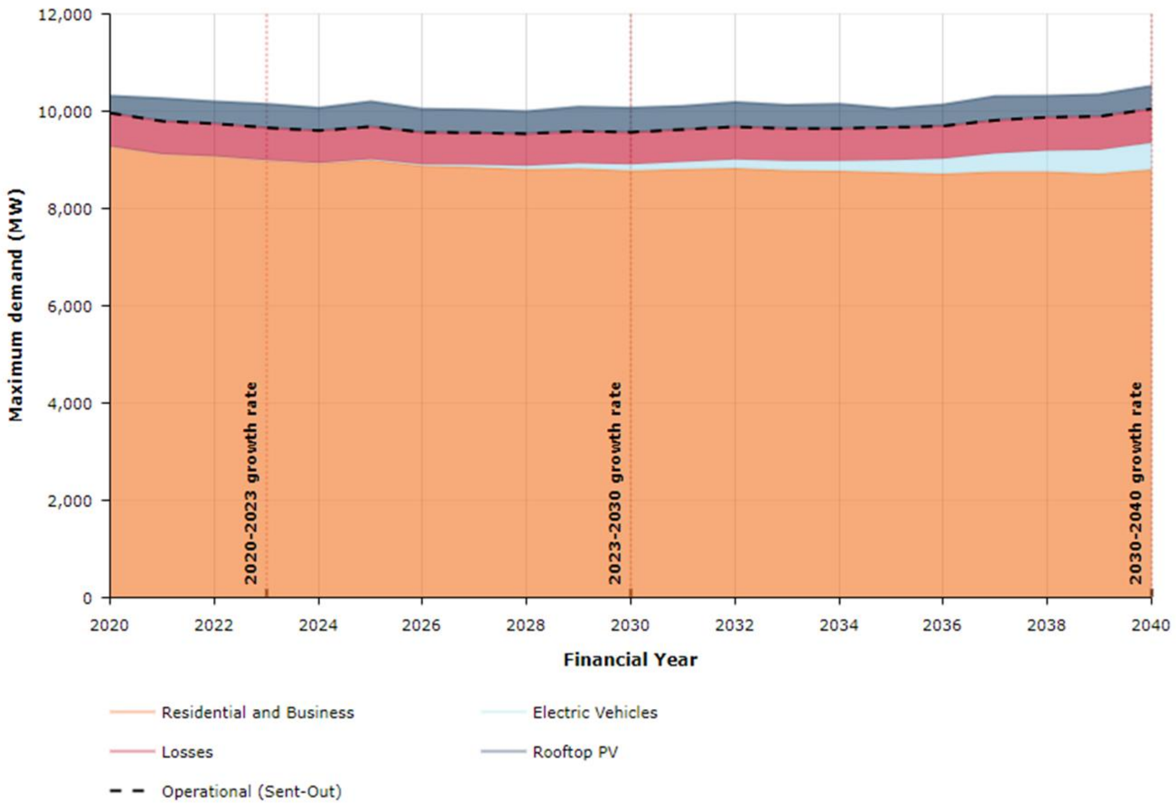
Source: Energy Networks Australia

The 2020 ISP, released by AEMO in July, also considers the implications of the pandemic in assessing and determining an optimal power system development pathway. In developing the ISP, AEMO assesses various energy future scenarios and the implications of the pandemic can be considered in this context. Notwithstanding that the pandemic is a further uncertainty in the scenario analysis and may modify outcomes, the ISP puts the pandemic in context, observing that its occurrence does not lessen the need for an optimal long term development pathway that facilitates the effective and efficient coordination of renewables integration to ensure a reliable and affordable energy supply.

2.2.7 Electricity demand and consumption trends

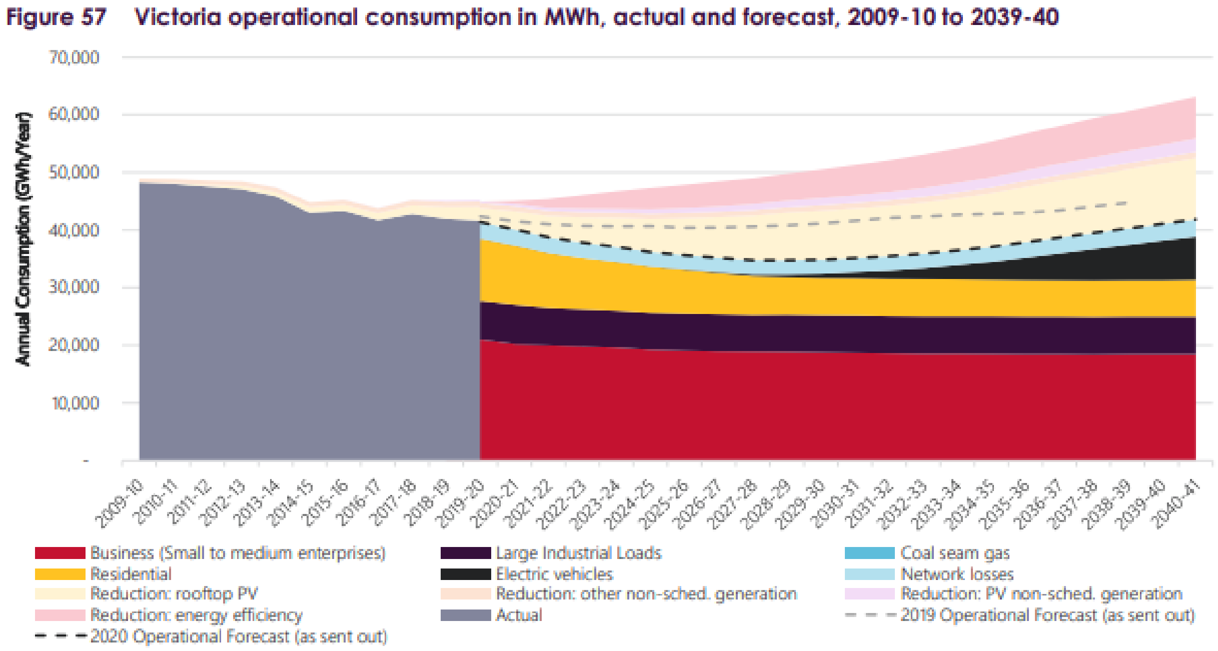
Historically, the electricity market was characterised by steadily increasing electricity consumption and peak demand. However, over the last decade the growth in both electricity consumption and peak demand has fallen, as shown in Figure 2-6 and Figure 2-7 below.

Figure 2-6: Maximum demand forecast (central forecast, 10% POE), Victoria



Source: AEMO forecasting portal http://forecasting.aemo.com.au/Electricity/MaximumDemand/Operational

Figure 2-7: Consumption, central forecast, Victoria



Source: AEMO, *2020 Electricity Statement of Opportunities*, page 107 https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en

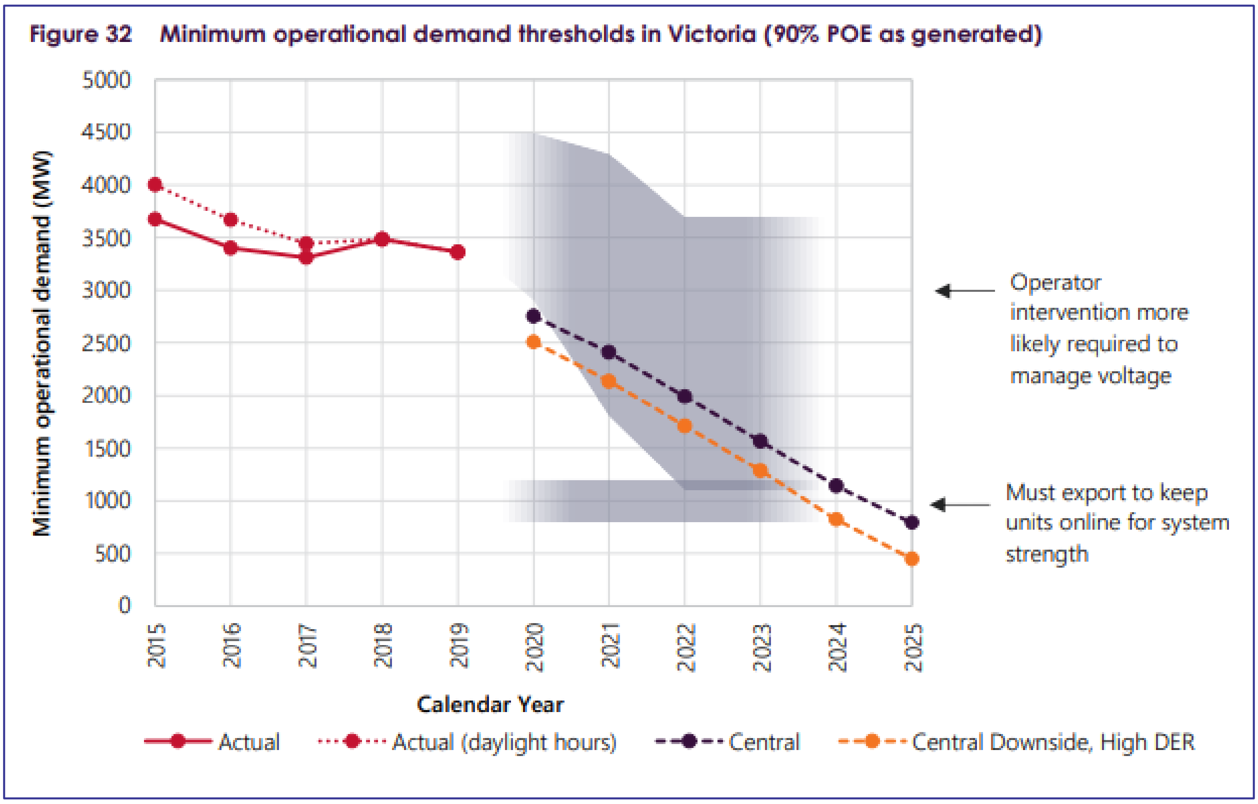
These trends can be explained by several factors, including:

- The flattening of demand and consumption has reflected structural changes in the Australian economy as the result of a shift from more traditional, energy-intensive activities (such as manufacturing) towards more service-based activities which generally use less energy.
- More recently, the increased penetration of embedded generation such as solar PV has reduced the consumption of electricity sourced from the grid. This source of energy continues to grow in the forecasts, and is higher than forecast in 2019.
- The forecast incorporates an expected increase in attention on energy efficiency.
- The forecast includes the uptake of electric vehicles, based on a slow uptake until 2028-29 after which the range of models, established charging infrastructure and costs are expected to encourage increased growth.
- A temporary slowing in business consumption and connections growth in response to COVID-19.

In addition, the minimum operational demand on the transmission system is declining rapidly with the uptake of distributed PV generation contributing to meeting of daytime consumer demand, and as distributed PV continues to be installed the trend will continue. This trend has already resulted in operational challenges associated with voltage control, and could also lead to system strength and inertia issues.[29] Figure 2.8 shows the forecast minimum operational demand for Victoria.

[29] AEMO, *2020 Electricity Statement of Opportunities*, August 2020, pages 4 & 76.

Figure 2-8: Forecast Minimum Demand



Source: AEMO, *2020 Electricity Statement of Opportunities*, page 7 https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en

These trends and the considerations of electricity consumers are taken into account in the development of this Revenue Proposal. The stakeholder engagement underpinning this Revenue Proposal is outlined in Chapter 3.

2.3 Recent achievements

This section highlights our key achievements during the current regulatory control period, many of which build on initiatives that commenced in previous regulatory periods.

2.3.1 Industry leading cost efficiency

AusNet Services costs are low compared to its peers on most indicators, and the lowest on a cost per end user basis.[30] We also perform strongly across the suite of benchmarking indicators published by the AER.[31] Our cost performance is discussed in further detail in Chapters 4 and 5.

This outcome, and our commitment to continuous improvement, reflects AusNet Services' efficient work practices and continuous effort to improve our business processes. Our asset base and opex per customer remains well below the level of our peers[32] due to the highly efficient approach we have taken to replacing assets since the network was privatised 23 years ago. The incentive properties of the revenue setting regime also contribute to incremental improvement in

[30] AER, *Annual Benchmarking Report, Electricity transmission network service providers*, Nov 2019, Figure 4.3.

[31] AER, *Annual Benchmarking Report, Electricity transmission network service providers*, November 2019.

[32] ibid, Figure 4.4.

cost performance. These outcomes have been achieved without compromising reliability and safety.

The benchmarking evidence, together with the analysis of the company's performance against the regulatory allowances and service performance targets, demonstrate that our expenditure and service performance is efficient. The fact that AusNet Services is commencing the forthcoming regulatory control period in circumstances where its costs and service performance compare well against its peers is important contextual information for assessing this Revenue Proposal.

2.3.2 CBD Terminal Station rebuilds

We have completed two highly complex brownfield projects at terminal stations supplying the Melbourne CBD and inner suburbs (Brunswick terminal station 2014 to 2016 completion - Richmond terminal station 2012 to 2019 completion) and are well on the way to completing a third terminal station at West Melbourne – commenced in 2017 and due for completion late 2021.

These three terminal stations are crucial to maintaining long-term, safe and reliable electricity supply to Melbourne's CBD and inner suburbs. The Richmond and West Melbourne projects involved rebuilding existing assets which were nearing the end of their operational life. The Brunswick Terminal Station rebuild and augmentation was completed at the request of CitiPower and AEMO in order to strengthen the security and reliability of the CBD electricity network.

Planning for each rebuild began many years prior to actual construction at the site, and only following extensive consultation with local communities and subsequent receipt of planning approval. In each case, works were completed whilst maintaining uninterrupted electricity service and ensuring the safety of all staff and contractors. To achieve this outcome required very complex, interlinked risk-managed schedules for works at each site. These rebuilt terminal stations will secure long term reliable electricity supply for our CBD customers.

2.3.3 Maintained ISO 55001 Accreditation

ISO 55001 is the internationally recognised standard for the optimised management of physical infrastructure assets. In early 2014, we were the first Australian transmission businesses to achieve certification to ISO55001 and were recertified in 2017. Earlier, we were the first transmission business in Australia to obtain certification to the predecessor standard PAS 55,[33] for our AMS.

Accreditation demonstrates that we have in place robust and transparent asset management policies, processes and procedures, and a sustainable performance framework. Maintaining our accreditation means that we remain an effective, efficient, and competent asset manager, with an industry-leading approach to asset management.

2.3.4 Delivered Network Capability Incentive Parameter Action Plan (NCIPAP) projects

We were the first TNSP to participate in the AER's Network Capability Component incentive (NCC), which is a part of the Service Target Performance Incentive Scheme (STPIS). The NCC parameter requires us to deliver a suite of specified low-cost projects directed at increasing the capability of existing transmission assets. AusNet Services is undertaking network capability improvement work equal to the maximum value permitted under the NCIPAP component.

We are progressing well with the delivery of the agreed projects, with three of the seven projects completed to date with an estimated net benefit of $7 million achieved so far. We expect this will rise to $20 million by the end of the current regulatory control period.

[33] British Standards Institute *Publicly Available Specification PAS 55-1 Part 1: Specification for the optimized management of assets*.

2.3.5 Established Transmission Revenue Reset Customer Advisory Panel

The stakeholder engagement undertaken as part of the development of this Revenue Proposal built on the engagement we undertook for the 2017-22 transmission revenue review. To assist us in understanding customer preferences and concerns and reflecting these in our plans, we established a Transmission Revenue Reset Customer Advisory Panel in March 2019. The purpose of the Customer Advisory Panel is to provide feedback and advice on:

- Electricity customers' needs, issues and services and how these should be addressed or incorporated in our plans; and
- The findings and insights obtained through our Customer Experience Program.

A Customer Advisory Panel (CAP) is an effective way to facilitate comprehensive stakeholder engagement with our transmission network plans because it enables us to talk and listen directly to all our transmission customers around one table. It was complemented by targeted deep dive sessions with customers and other key stakeholders.

The membership of the CAP reflects the diversity of the customers and stakeholders that depend on the transmission network, including those customers that directly engage with the network and residential and commercial customers that do not. Further information about the operation of the CAP and its impact on the development of this Revenue Proposal is provided in Chapter 3.

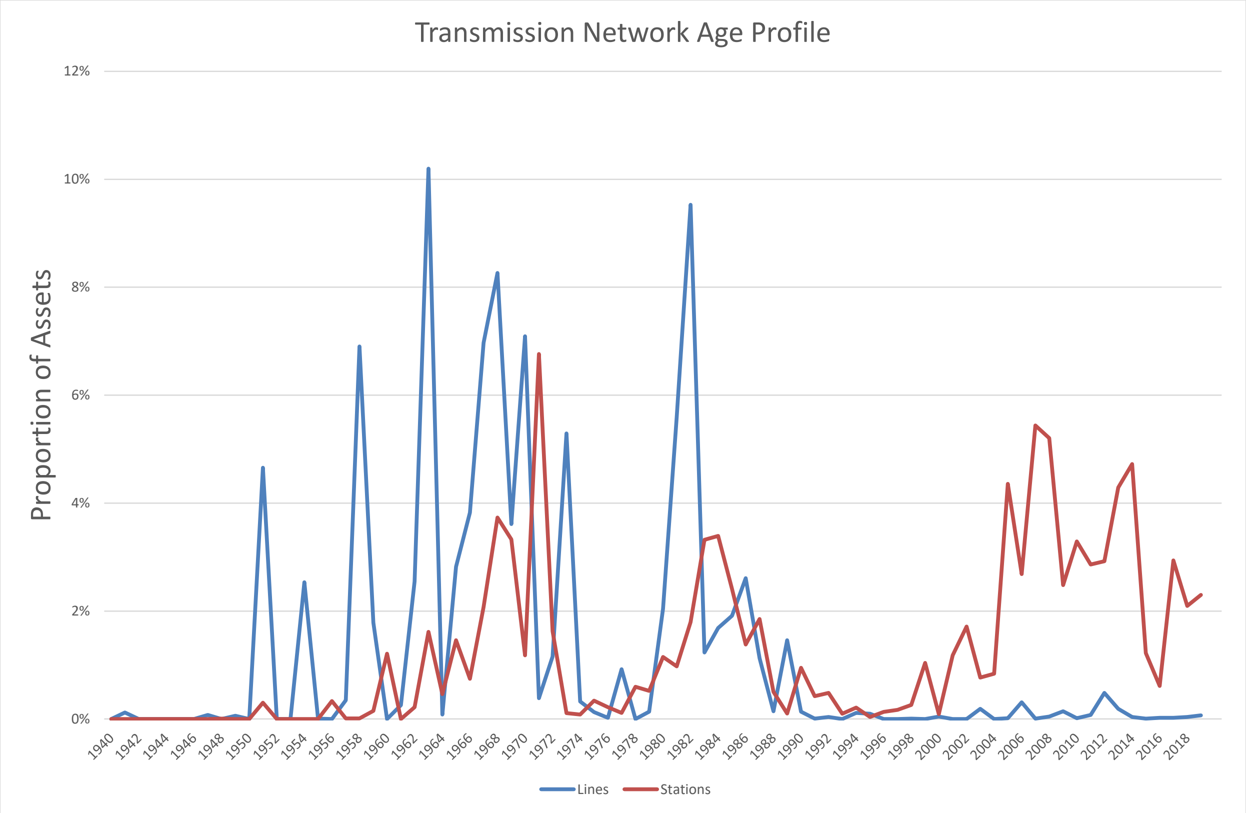
2.4 Ongoing challenges

This section outlines key asset management challenges we face in the evolving energy sector environment.

2.4.1 Ageing assets

An increasing share of our assets are expected to reach the end of their technical lives during the next regulatory control period. The figure below shows that a material proportion of lines assets have exceeded a 60-year life and a number of stations assets are approaching 60 years.

Figure 2-9: Network age profile



Source: AusNet Services

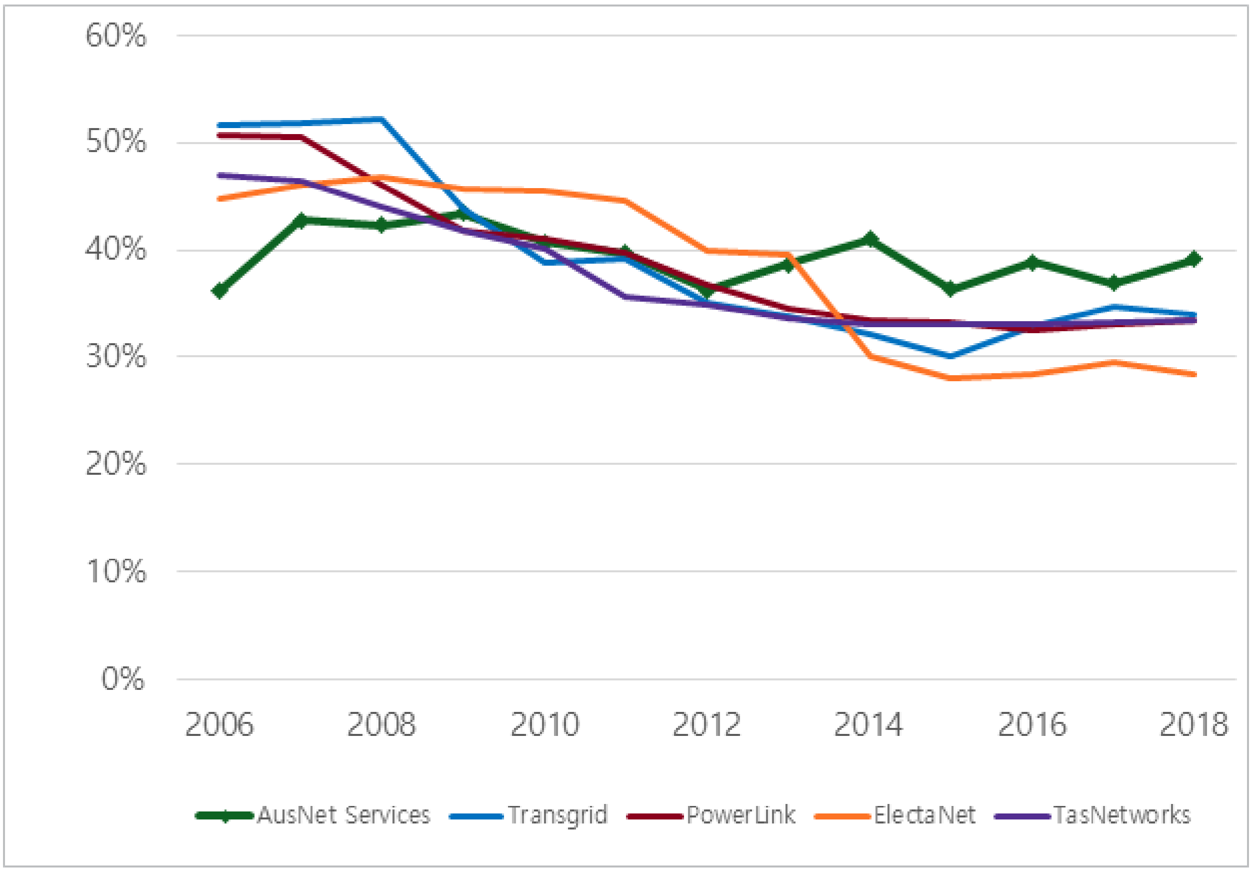
The correlation between asset age and condition means that the ageing nature of our asset base is a key driver of the increase in capex being forecast for the next regulatory control period. However, this only provides an indicator of asset replacement needs. It is the assessed actual condition of assets that determines the detailed asset replacement forecast. Furthermore, it is important to note that even then, replacement decisions for major assets are based on economic justification, taking into account the probability of failure and the probability of consequences arising from failure, which include safety, environmental and financial consequences of failure, as well as network performance consequences.

Effective asset management, based on condition and criticality rather than age, enables AusNet Services to identify opportunities to efficiently defer the replacement of some assets. This maximises the service life of existing assets and minimises long-term costs to customers.

By applying a probabilistic planning technique, our asset management approach ensures investment plans are economically efficient. Under this approach, the cost to network users and to the public from an asset failure is weighted by the probability of that occurrence and a deteriorated service. Asset management decisions to invest must then demonstrate a net cost benefit compared to the business as usual (no investment) approach. Adoption of this approach across asset replacement and augmentation investment decision making in Victoria is reflected in the high capacity utilisation of the Victorian transmission network compared to our peers in other states, as shown in Figure 2-10 below.

While the probabilistic planning technique leaves some residual service interruption risk on the network, it maximises the economic value that we can extract from our assets on behalf of our customers whilst ensuring that we meet their expectations regarding reliability. As explained in section 2.5.2, our plans also recognise that the safety of our customers, the community and our employees is our highest priority and is never compromised.

Figure 2-10: Transmission network capacity utilisation in the NEM



Source: AusNet Services

2.4.2 Operating considerations

The operational flexibility of the Victorian transmission system has reduced over time as large baseload generation has closed (Hazelwood and Morwell power stations in Victoria) and parts of the network designed to serve load are now relied upon to dispatch new renewable generation. As a result, there is increasing dependency on the normal configuration of the network, requiring each network element to be in service. As a result of the changes in the way the network is utilised, AusNet Services must adapt to this developing operating environment.

In particular, the changing and increasing utilisation of the network has the effect of restricting the opportunities AusNet Services has to take outages that are essential to our ability to switch the network for critical maintenance and project works, and which now apply over longer timescales. Lines subject to restricted access have grown to include all the 500 kV network and a significant proportion of the 220 kV network, 19 lines in total. This compares with just 6 lines in South Australia, 2 in New South Wales and none in Queensland.

In addition to access for work limitations, the changing nature of the network has implications for other aspects of network and asset management. For example:

- An increasing complexity for the design of protection, communications and control schemes resulting from an increasingly weak rural 220 kV network and operation with many new generator connection points; and

- Gaining full understanding of, and treating the potential effect of, changing duty on some network equipment, e.g. transformers.

With the generation fleet transitioning to variable renewable generation, and being increasingly dispersed across the network, network control centre activities are becoming substantially more complex. There is a priority focus on control centre information and decision-making support systems capability in this increasingly complex environment.

2.4.3 Challenges from closure of large generating stations

As a result of the closure of significant baseload generation in the Latrobe Valley, the transmission pathways for Latrobe valley generation are more limited as the remaining generation is concentrated at fewer terminal stations. The availability of interconnectors is now, therefore, vital to ensure Victoria and South Australia (which has also lost significant baseload generation) can access enough electricity on high demand days. The vulnerability of the system to single switched transmission elements connecting generator units and key lines has also increased.

The resulting shifts in the reliability and security risk profile of the network highlight the need for a strong focus on network resilience in our asset management plans. The changing risk profile will need to be monitored into the future and will outwork in the focus of key replacement and maintenance programs, spares holdings and strategies, and consideration of alternative switching configurations at critical stations and generator connection points.

2.4.4 Meeting community expectations regarding network reliability

As existing assets age and their conditions deteriorate, the risk of failures increases. This may result in supply interruptions. The AER's VCR values are a key input into how we determine when to replace assets on our network. The VCR represents the monetary value that different types of customers place on having access to a reliable electricity supply and takes into account different loss of supply scenarios, such as short duration, prolonged and widespread outages. The VCR, therefore, reflects the trade-off customers face between the reliability and affordability of their electricity supply.

For example, if the VCR shows that customers would prefer a lower level of reliability, then less investment may be required in order to achieve that level of reliability, thus reducing long run costs to consumers through lower electricity bills.

The VCR was reviewed and updated by the AER in December 2019. In developing the values, the AER surveyed over 9,000 residential and business customers of various sizes and industries across eastern and south-eastern Australia and the Northern Territory. The VCRs developed by the AER, in relation to residential customers, are specific to climate zones and locations (regional or urban), whilst for the business customers VCR values are set according to business segment (agriculture, commercial or industrial).

VCR values may be derived for each state, network, or network segment using the AER information. In its Final Report on VCR Values, the AER derived residential VCR values for each state and the change compared to previous estimates.[34] This analysis shows that the Victoria-wide residential VCR is the lowest of the mainland NEM states, and has seen the most significant reduction in VCR value across these states.

As AusNet Services' asset investment plans are grounded in economic considerations, the VCR has a direct bearing on our investment decisions. A lower VCR implies a higher level of expected

[34] AER, *Values of Customer Reliability, Final Report on VCR Values*, December 2019, table 1.2.

unserved energy before investment can be justified, allowing for a lower level of investment in the network overall.

2.5 Asset management approach and compliance obligations

This section describes our asset management practices and our compliance obligations, both of which are key inputs to our expenditure plans.

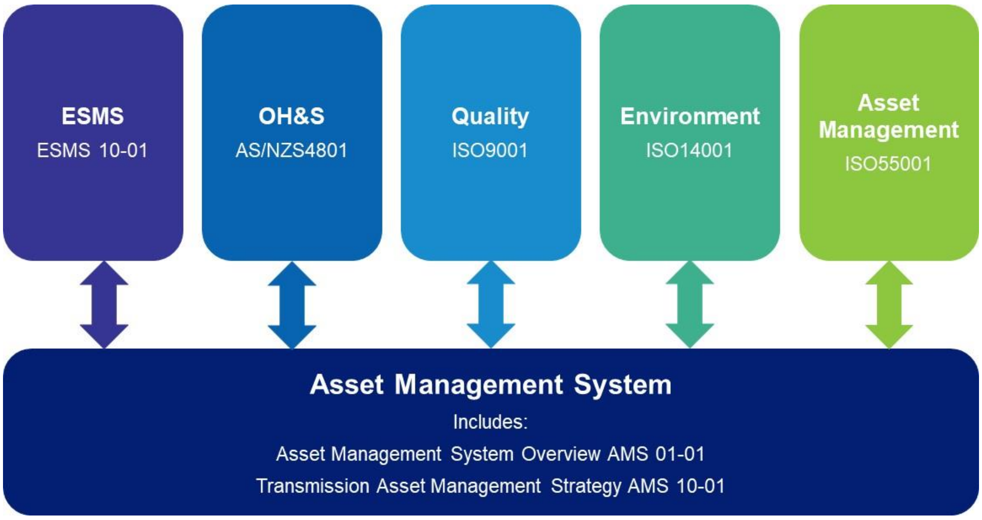
2.5.1 Asset management practice

AusNet Services has demonstrated a commitment to providing a safe, efficient and reliable transmission network. In addition to our Electricity Safety Management Scheme (ESMS), which is approved by Energy Safe Victoria (ESV), we maintain quality assurance over our Asset Management System through certification to:

- AS/NZS 4801 -- Occupational Health & Safety Management Systems;
- ISO9001 – Quality Management Systems;
- ISO14001 – Environmental Management System; and
- ISO55001 – Asset Management.

The figure below depicts these policies, processes, procedures and standards, which together define our strategic objective of providing our customers with a safe and reliable electricity supply.

Figure 2-81: Asset Management System Certification & Approval



Source: AusNet Services

Our asset management policies, processes, procedures, and practices provide important context for the expenditure plans and forecasts for the forthcoming regulatory control period. In particular, the Asset Management System (AMS) aims to stabilise the risks associated with the electricity transmission network. Asset risk is expressed as the probability of asset failure (determined using asset condition data) multiplied by the impact of that failure on network safety, reliability and availability. This approach to asset management establishes an economic basis for evaluating investment decisions.

As already noted, AusNet Services was the first transmission company in Australia to obtain PAS 55[35] certification for its AMS. In early 2014, our asset management practices were certified

[35] British Standards Institute *Publicly Available Specification PAS 55-1 Part 1: Specification for the optimized management of assets*.

to ISO 55001, the internationally recognised successor to PAS 55. The adoption of ISO 55001 enables an organisation to achieve its objectives through the effective and efficient management of its assets. It is applied where physical assets are a critical factor in achieving business objectives and its application provides assurance that those objectives can be achieved consistently and sustainably over time.

Certification demonstrates robust and transparent asset management policies, processes, procedures, practices and a sustainable performance framework. Certification is a strong supporting indicator that AusNet Services is an effective, efficient and competent asset manager.

2.5.2 Compliance obligations

Our compliance obligations are key drivers of our expenditure plans. The remainder of this section summarises our safety and regulatory obligations.

Safety obligations

Safety is the first of four corporate values for AusNet Services. This value confirms that AusNet Services never compromises safety. Consistent with this value, we are committed to providing a safe, efficient, and reliable transmission network.

The company's commitment to safety is underpinned by legal requirements to maintain a safe working environment for employees, and to minimise any risk to public safety presented by its operations. These requirements are set out in the following Acts:

- *Occupational Health and Safety Act 2004* (Vic), which this sets out requirements to protect the health and safety of our staff;
- *Electricity Safety Act 1998* (Vic) (ESA), which sets out legal responsibilities to ensure public safety. The requirements of this Act are addressed in our ESMS for our electricity transmission network.

We are also subject to mandatory obligations set out in the NER and the transmission licence issued by the Victorian Essential Services Commission (ESC). The suite of key legal and regulatory obligations, which include operational requirements, are outlined in the figure below.

Figure 2-92: Key Operational Legal and Regulatory Obligations

Victorian Electricity System Code and Transmission Licence	Australian Standards	Electricity Safety Management Plan	National Electricity Rules
• System performance obligations	• AS/NZS 7000 • AS 62053 • AS 2067	• Approved by ESV • Safety system operation	• System security obligations • Connection obligations • Metering obligations • Economic regulation

In addition, clause 98 of the ESA imposes the following requirements on AusNet Services:

> *A major electricity company must design, construct, operate, maintain and decommission its supply network to minimise as far as practicable –*
>
> *(a) the hazards and risks to the safety of any person arising from the supply network;*
>
> *(b) the hazards and risks of damage to the property of any person arising from the supply network; and*
>
> *(c) the bushfire danger arising from the supply network*

Electricity Safety (Management) Regulations 2009 (made under section 150 of the Act) set out the requirements for an ESMS. An ESMS is compulsory, and effectively covers all documentation, procedures, accreditation, monitoring and reporting of work on or for designing, installing, operating, maintaining, and decommissioning network assets. As noted in section 2.5.1, the ESMS must be submitted to ESV every five years for acceptance and is audited by ESV.

AusNet Services is also required to comply with health and safety, environmental and security obligations which impact on the design and operation of the network. These obligations and the related internal standards cover matters such as:

- Safe access for work on towers;
- Management of fire hazards;
- Changes to the Occupational Health and Safety Act 2004 requiring additional reviews of safety issues at the design stage of a project and additional liability (and therefore cost) for designers;
- Management of various pollutants and environmental effects (oil discharge, noise and greenhouse gas emissions); and
- Physical security.

These obligations have a substantial bearing on the level of forecast capital expenditure that will be incurred by AusNet Services in the forthcoming regulatory period, to ensure the provision of safe transmission services.

The Environment Protection Act 1970 empowers the Environment Protection Authority (EPA) to issue regulations and other compliance instruments relating to the protection of the environment. Areas covered by the legislation include:

- Part V – Clean Water
- Part VI – Clean Air
- Part VII – Control of solid wastes and pollution of land
- Part VIII – Control of noise
- Part IXA – Transport of prescribed waste
- Part IXD – Environmental audits

This Act will be repealed when the *Environment Protection Act 2018 (Vic)* commences on 1 July 2021. These legislative amendments will impose new environmental protection obligations on AusNet Services from that date. These include, most notably, the introduction of a general environmental duty, a duty to manage contaminated land and a duty to notify of contaminated land. To meet these new obligations, we have forecast an opex step change of $3.1 million to establish a new testing regime. This is discussed further in Chapter 4.

Following the commencement of the EPA amendments, AusNet Services will also be required to test for historical contamination and notify the EPA of any contaminated land sites. No provision has been made in this Revenue Proposal for the cost of managing a site that is found to be contaminated. However, it is possible that these costs could be significant. Due the uncertain nature of these costs and the difficulty of preparing an accurate forecast, AusNet Services considers this risk is most appropriately addressed by a nominated pass-through event. This is discussed further in Chapter 12.

Part 7A of the Victorian *Emergency Management Act 2013* and the following instruments made pursuant to it, set out requirements for protecting critical assets from emergencies:

- Emergency Management (Critical Infrastructure Resilience) Regulations 2015; and

- Critical Infrastructure Resilience Strategy.

These regulations refer to relevant guidance from the Australian Government that must be adhered to, including the Australian Emergency Management Handbook Series.

In summary, the obligations referred to above have a substantial bearing on the expenditure that AusNet Services will be required to incur in the provision of prescribed transmission services over the forthcoming regulatory control period. Pursuant to NER 6A.6.7(2), our capital and operating expenditure forecasts include the costs of complying with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services, with the exception of those costs which we consider should be managed using cost pass-through arrangements.

Reliability obligations

AusNet Services is also responsible for ensuring that the reliability of our transmission network is maintained, subject to the planning decisions made by AEMO. Reliability obligations are set out in:

- The Victorian Electricity System Code (October 2000) which requires us to undertake our activities as a Victorian transmission network service provider in a safe, efficient, and reliable manner;
- Chapter 4 of the NER, which applies to system security obligations; and
- Chapter 5 of the NER, which prescribes connection obligations.

In addition to reliability obligations, we must also comply with other obligations, including AEMO's system operation procedures for transmission businesses. As already noted, the expenditure required to comply with these obligations must be reflected in our expenditure plans.

While it does not specify reliability obligations, the AER's Service Target Performance Incentive Scheme (STPIS) provides incentives to improve reliability. It consists of the following three components:

- **Service Component –** provides an incentive in the form of a financial reward or penalty to reduce the occurrence of unplanned outages and to return the network to service promptly after unplanned outages.
- **Market Impact Component (MIC)** – provides an incentive in the form of a financial reward or penalty to reduce the impact of planned and unplanned outages on wholesale market outcomes. We consider the incentives provided by the MIC are no longer appropriate due to the significant and rapid changes occurring in the energy system and, therefore, encourage the AER to review this component of the STPIS. This issue is discussed further in Chapter 7.
- **Network Capability Component** – provides a financial incentive to deliver benefits through increased network capability, availability, or reliability through one-off projects.

Chapter 7 sets out AusNet Services' proposed approach to the application of the STPIS during the forthcoming regulatory control period.

2.6 Supporting documents

The following supporting documents are relevant to this chapter:

- Appendix 2A – Asset Management Strategy.
- Appendix 2B – ISO 55001 Accreditation.

3 Customer & stakeholder engagement

3.1 Key points

The key points in this chapter are:

- We define customers as the 'end-users of the energy that we transport'. This includes residential and small business customers as well as large directly connected customers, generators and stakeholders utilising our transmission network.
- Over the past two years, we have set out to systematically listen to and gather insights on what our customers and stakeholders think about the services we provide. Our ongoing customer engagement program is a key mechanism through which we reflect customer views in our strategies, plans and how we deliver our services.
- We established a dedicated Transmission Customer Advisory Panel (CAP) to assist and advise us in the development of our 2023-27 transmission plans. The Panel has helped guide our engagement activities and areas of focus.
- We have reflected the views of customers and stakeholders in several key aspects of our Revenue Proposal, including the operating expenditure step changes we have proposed and the profile and timing of our network capital expenditure forecast. By listing to our customers and stakeholders, we have been able to reduce our proposed revenue requirement by $8 million over the forthcoming regulatory control period.
- As a result of COVID-19, we decided not to release a draft proposal as initially planned to allow for adequate consideration of any impacts on our plans. We will continue to engage with customers and stakeholders on the impact of COVID-19 and reflect any new information, including AEMO's latest demand forecasts, in our Revised Proposal.

3.2 Chapter structure

This chapter is structured as follows:

- Section 3.3 provides an introduction and context to our customer engagement program.
- Section 3.4 summarises our ongoing customer engagement program.
- Section 3.5 explains our customer engagement approach and objectives, and targeted activities undertaken to inform our 2023-27 transmission network plans.
- Section 3.6 sets out what we heard from customers and stakeholders through our engagement program and how we have responded to this feedback in our plans.

3.3 Introduction and context

AusNet Services' electricity transmission network plays a critical role in delivering reliable power to over 2.1 million households and businesses in Victoria and supporting reliable, lower cost electricity supply to other customers across the National Electricity Market (NEM).

The energy generation mix in Australia and across the world is changing and we believe this change should ultimately mean reduced emissions and more affordable power for all our customers. Different jurisdictions face different challenges as they adapt to these changes. In Victoria, the combination of coal-fired generation retirements and demand for renewable generation connections in the weakest part of our network presents challenges for system security and strength.

The 'end-users of the energy that we transport' are our customers, along with the customers directly connected into the transmission network. While not energy users, new generators seeking connection to the Victorian transmission network are key stakeholders of AusNet Services' and play a key role in the transition to a low carbon energy system. While AEMO holds responsibility for the connection of new generators in Victoria, we work closely with AEMO to facilitate the connection process. So, we are an integral part of the energy supply chain.

Transmission charges in Victoria comprise both AusNet Services' transmission costs and the planning and procurement costs of AEMO, the Victorian jurisdictional TNSP. The affordability of transmission services in Victoria is, therefore, dependent on the efficiency of both of these cost components. Whilst our transmission network charges only account for a relatively small proportion of a residential and small business customer's bill (approximately 6%), network charges for large energy users will account for a considerably higher portion of their energy costs.

The results from the most recent Energy Consumer Sentiment Survey demonstrated that nationally, satisfaction with value for money for electricity has been trending upward, reaching its highest levels since tracking started three and half years ago at 53% for households.[36] However, it remains well behind satisfaction with other utilities such as mobile phone providers (74%), banking (71%) and internet providers (68%). If the industry is to successfully bridge this deficit, and overcome this perceptual barrier, significant efforts need to be made to demonstrate to customers that the industry is operating in their long-term interests.

Over the past two years, we have set out to systematically listen to and gather insights into what our customers think, and to better reflect these views in our strategies, plans and how we deliver our services. This represents a deliberate shift in our approach to customer engagement, and we have embedded these practices as part of business-as-usual approach, moving it beyond regulatory reviews.

A key part of the shift towards greater customer centricity has been the implementation of our company-wide Customer Experience Program and a new and externally captured Customer Satisfaction measure in February 2018. We appointed Customer Service Benchmarking Australia (CSBA) as the independent research agency to conduct qualitative interviews with our transmission customers, some of which are also represented on the Customer Advisory Panel. The Customer Experience Program is an ongoing program aimed at improving customer experience, at no additional cost to customers. This process identified opportunities to improve engagement, industry alignment and collaboration, and simplify processes. These insights have been used to inform the pipeline of work designed to improve the customer's experience and our business strategy.

At the same time, we have also sought to be more innovative in our approach to customer engagement by moving towards the Involve, Collaborate and Empower levels (of the IAP2 Public Participation Spectrum[37]). This has been reflected in the ground-breaking initiative that we developed in conjunction with the AER and Energy Consumers Australia as part of our recent Electricity Distribution Price Review to ensure customers' views are reflected in our future expenditure and service plans. Central to this initiative was the establishment of a Customer Forum, comprising highly skilled customer representatives, to work with us to drive a more customer-focused proposal. The Customer Forum has also helped to guide a substantial customer research program to gain deeper insights into our customers.

[36] *Energy Consumer Sentiments Survey Findings: June 2020 & COVID Special Report*.

[37] The IAP2's Public Participation Spectrum is designed to assist with the selection of the level of participation that defines the public's role in any community engagement program. The Involve, Collaborate and Empower levels represent the higher end of the spectrum, engaging with engagement participants playing a key role in decision-making.

The overlapping timing between the commencement of this transmission regulatory review process and the on-going Electricity Distribution Price Review has allowed the distribution review to play an important role in informing and shaping our approach to engagement for this proposal:

- The distribution review process provided a wealth of current research about electricity end-user views and preferences. While this research focussed on identifying the preferences and needs of residential and business customers connected to the distribution network, many of the key themes and insights from that research are also relevant to the development of plans for our transmission network.
- Leveraging the insights from the extensive customer research undertaken as part of developing our regulatory proposal for our electricity distribution network ensured our engagement program for this transmission proposal reflected the views of end-users. It also allowed us to prioritise and target our engagement efforts towards directly connected customers and other key stakeholders in an efficient and cost-effective way.
- Influencing our decision to establish a Customer Advisory Panel (CAP). Whilst the Customer Forum has been effective in bringing a stronger voice of the customer to our electricity distribution review and across AusNet Services more broadly, we considered that a CAP is a more fit-for-purpose, lower cost and effective method for engaging with transmission customers and stakeholders; and
- Identifying key customer views and preferences for engagement with the CAP. As AusNet Services has recently embarked on its most significant program of customer research and engagement to date, we sought to leverage this research rather than duplicate efforts by validating these themes and identifying any gaps with the CAP.

The COVID-19 pandemic has presented challenges for effective customer engagement, requiring us to adapt our engagement methodologies. We also recognise that the pandemic's economic effects are likely to be ongoing. Given the timing of this submission, it has not been possible to anticipate the impact of the pandemic or reflect customers' perspectives on this issue in this Proposal. Rather, we intend to conduct a consultative process on these effects with customers and stakeholders in the first quarter of 2021, after this proposal is submitted. This allows time for detailed information, such as effects on energy demand, to be collected, assessed and considered, allowing for a more considered discussion as a result. The feedback from this engagement will be addressed in the Revised Proposal.

3.3.1 The split of responsibilities for Victoria's transmission network

An important factor that influenced the design of AusNet Services' stakeholder engagement program is the split in responsibilities for the transmission network in Victoria. Uniquely in Victoria, AEMO is responsible for planning augmentations of the shared transmission network while customers, whether generators, directly connected large customers or distributors, plan the augmentation of transmission connection points. Proposals for network augmentation are, therefore, not included in AusNet Services' Revenue Proposal.

However, the need for significant investment in new transmission capacity over the next decade, as set out in AEMO's 2020 Integrated System Plan (ISP), has generated intense stakeholder and customer interest. Therefore, AusNet Services and AEMO worked to identify opportunities for both parties to collaborate on joint engagement with common stakeholders. This included running joint briefing sessions on the customer implications of both AusNet Services' forecast replacement expenditure and the augmentation investments set out in the ISP, which is procured by AEMO in Victoria under contestable arrangements.

AEMO staff responsible for planning the Victorian transmission network also attended AusNet Services' Customer Advisory Panel meetings. This enabled stakeholders to raise issues related to the Victorian transmission network, regardless of whether these issues involved AusNet Services or AEMO.

3.3.2 The use of AEMO's Value of Customer Reliability (VCR) estimate

AusNet Services' use of AEMO's Value of Customer Reliability (VCR) estimate in planning the timing of asset replacements also influenced the engagement program. The Value of Customer Reliability (VCR) is a key input into how we determine when to replace assets on our network. The VCR represents the monetary value different types of customers place on having access to a reliable electricity supply under different conditions, such as short outages and prolonged outages. The VCR, therefore, reflects the trade-off customers face between the reliability and affordability of their electricity supply.

The VCR was reviewed and updated by the AER in December 2019. In developing the values, the AER surveyed over 9,000 residential and business customers of various sizes and industries across eastern and south-eastern Australia and the Northern Territory. The VCRs developed by the AER are specific to climate zones and locations (regional or urban). As discussed in Chapter 4, we have used the updated VCR in developing our network investment plans, reflecting customers' current preferences regarding both price and reliability. This ensures that consumer preferences on reliability are reflected in our capex proposal in a robust manner.

As the VCR is an independently derived and statistically robust means of capturing consumer preferences for price and reliability in our transmission investment plans, the purpose of our engagement program was not to duplicate the extensive research carried out to inform the VCR estimate (e.g. through a large-scale and costly willingness to pay survey). Rather, the engagement program sought feedback on more targeted aspects of our plans where customer views could influence decisions taken in our Revenue Proposal.

3.4 Our ongoing customer engagement program

There has been a deliberate shift at AusNet Services over the past two years to systematically integrate customers and stakeholders into the development of our strategies, plans and how we deliver our services. This is intended to engage those directly impacted by our decisions and services, or their representatives, outside of regulatory review processes. The specific activities that we undertake as part of our ongoing (regular) customer engagement, that are being used to inform our future plans for the transmission network, are described below.

Table 3-1: Summary of ongoing customer engagement activities

Activity	Description
Customer Consultative Committee	This committee is responsible for providing customer input into decision making within AusNet Services. It serves as a direct channel for external customers' perspectives. The Committee meets monthly. The Committee provides an ongoing forum in which a range of customer issues can be discussed by a select group of community or customer representatives, people with expert knowledge about specific and general customer issues. The Committee is independently chaired and comprises of six AusNet Services representatives, including senior executives and management, and eleven external representatives from a range of customer interest and community groups.

Activity	Description
Customer Service and Experience Program	Our company-wide Customer Experience program is an important lever in our move towards becoming a more customer centric-organisation. This is an ongoing program to improve customer experience. Within the Customer team, we have established a Customer and Industry Engagement team to provide a direct contact point for large users and proactively address customer concerns and issues. We are developing and implementing ways to improve the customer experience and eliminate "pain points" for all customers seeking to access our services. We have undertaken preliminary research to better understand the experience of new generators connecting to the transmission network. We are now considering these insights and the specific actions that need to be undertaken to address them. See Box 1 for details.
Infrastructure project community engagement	Major infrastructure projects on the transmission network can have a significant noise and visual amenity impact on the surrounding community. We recognise that to deliver these projects successfully it is important that stakeholders with a local interest, including local Councils, community groups and community members, are engaged in the process, from planning to implementation. The level of engagement appropriate to each project varies widely. As such, project-specific strategies are developed at an early stage, assisted by our Stakeholder Engagement Framework. This framework is built upon the principles of the International Association of Public Participation (IAP2). For example, we undertook significant engagement with local Councils and communities during a series of CBD terminal station rebuilds. This engagement included consultation throughout the planning permit approval process (with emphasis on hearing and where possible including local community preferences) via workshops, surveys, newsletters, and town hall style meetings. During the construction phase we regularly met with local Council on site, ensuring any community or Council concerns were addressed appropriately. We also: established a Community Reference Group with membership from AusNet Services, the Council and community to ensure appropriate accountability; sent regular newsletter updates on project progress; maintained a dedicated phone hotline and project website to gather and respond to enquiries or complaints; and holding one on one meetings with local residents who held specific project-related concerns. Recognising that there will be an increasing volume of infrastructure projects on the transmission network in the coming years, AusNet Services is embedding this

Activity	Description
	expertise into our infrastructure planning team. These internal specialists are supported, where appropriate, by external engagement specialists to both plan and deliver engagement strategies.
Reputation Research	This research was designed to measure corporate reputation on an ongoing basis, assisting proactive planning, and reputation and issues management. It was first undertaken in 2019, comprising qualitative and quantitative research to establish base levels of awareness and understanding of the AusNet Services brand, identify key facts and information to drive favourability of the brand, identify trusted voices, preferred sources of information and messaging for target audiences to enhance brand perceptions, and establish baseline measures and key performance indicators and track them over time. We use these insights to inform changes to strategy and communications across both electricity distribution and transmission. During March 2019, we conducted qualitative research in the form of face-to-face group discussions and online group discussions with 55 residential and small to medium business customers from AusNet Services' electricity distribution area. This qualitative research was used to inform the design of the questionnaire for a quantitative study of 800 customers in May 2019.
Customer Satisfaction Research **(transmission)**	Our regular customer satisfaction program comprises both qualitative and quantitative research. Qualitative research, in the form of face-to-face interviews, is conducted by internal staff for our transmission network. Specifically, we sample 12 – 15 directly connected customers, consumer advocates, distribution network businesses, generators and AEMO on a yearly basis to garner a better understanding of our current performance and areas for improvement. We also use these interviews as an opportunity to gather feedback on our transmission plans for the 2023-27 regulatory control period.
Customer Satisfaction Research **(electricity and gas distribution)**	Monthly telephone calls made to gas and electricity distribution customers constitute the principal quantitative component of the program. The operational activities assessed in the survey include planned and unplanned outages, new connections (including solar and battery for electricity) and complaints. Customer Service Benchmarking Australia (CSBA) delivers the program on our behalf. Insights gained from these customers are a valuable source of data on end-user customer preferences, which helps to inform our transmission plans.

Box 1: Generation Connection Process - Preliminary Insights

Generators drive the grid connection process for their generation project. Our research has shown that generators find the process increasingly complex, and need more help navigating this process. Further, generators feel they do not receive the level of support they expect as a customer. Delays in the connection process can complicate and delay when new generation projects can be brought online. This can impact materially on the project's finances.

While AEMO has primary responsible for the connection of new generators in Victoria, to respond to these concerns we are developing and implementing ways to improve our role in the generation connection process. Importantly, we expect these changes will not only improve the experience for our generator customers but are critical part of accommodating the substantial growth in generation applications. We recognise that timely connection of new renewable generation is a key part of energy system transformation.

The growth in connection enquiries heightens the importance of streamlining and enhancing the generation connection process so that our customers have confidence that AusNet Services is working constructively and efficiently to meet their requirements.

We also recognise that the current transmission arrangements in Victoria, where both AEMO and AusNet Services play a role in the connection process, can be a source of frustration for our customers, despite our best efforts to ensure a smooth and efficient process. Notwithstanding this, the key cause of delay in many grid connection processes is typically the need to address power system issues where generators attempt to connect in a part of the network where renewable resource is attractive but the electricity system is weak.

3.5 Our targeted reset customer engagement program

3.5.1 Engagement approach

To complement our ongoing engagement activities, we undertook targeted engagement with customers directly connected to our network, consumer advocates and other stakeholders on our plans for the transmission network.

Our customer engagement program comprises four key phases:

Phase 1 Design: Develop our customer engagement objectives and approach and identify key stakeholders and engagement themes. A critical input to this phase is the insights we gained through our ongoing engagement program, as well as the customer engagement and research carried out recently as part of developing our electricity distribution plans for 2021-26.

Phase 2 Listen: Engage with both customers directly connected to the transmission network, and interested stakeholders impacted by AusNet Services, and wider stakeholder groups representing customers. This phase involved a series of Deep Dive workshops, two Briefing Sessions and regular engagement with the Customer Advisory Panel. These activities are discussed below.

Phase 3 Respond: Consolidate and validate feedback heard during the listen phase and evaluate how we reflect this feedback in our plans for the next regulatory period and respond to the feedback in our business operations.

Phase 4 Post-lodgement engagement: Due to the wide-reaching implications of COVID-19, we were unable to publish a draft proposal for public consultation in April 2020 as initially planned, prior to formal submission of this Revenue Proposal to the AER. In recognition of this, we have planned more extensive post-lodgement engagement activities to seek feedback for consideration as part of any revised proposal submissions. This engagement will include details on how our plans have been impacted by COVID-19.

3.5.2 Phase 1 Design

3.5.2.1 Objectives and approach

The objectives of AusNet Services' targeted transmission revenue reset (TRR) engagement program were to:

- Understand whether, and in which areas, differences exist between what energy end-users and our directly connected customers and stakeholders' value in our service;
- Determine how we could align the Revenue Proposal to reflect customer and stakeholder preferences where possible and deliver value to all customers;
- Ensure customers and stakeholders understand how their preferences are reflected in the Revenue Proposal (including through the VCR) and, where this is not possible, explain why this is the case; and
- Continue to build our capacity and capability to develop proposals with critical input from customers and stakeholders through adopting multiple and alternate forms of engagement.

AusNet Services was undertaking engagement on the Electricity Distribution Price Review at the time we commenced planning for our Transmission Regulatory Review. The overlap between these two regulatory processes, coupled with the insights that we had already gathered via our ongoing customer engagement program, led us to develop a highly effective, targeted engagement program in relation to transmission.

Through our customer satisfaction program, we completed stakeholder mapping and identified the issues that were of importance to each stakeholder group. We were also able to leverage the learnings from a series of research efforts that we had undertaken during the distribution regulatory review to prioritise the issues that we wanted to engage our transmission customers and stakeholders on.

Accordingly, the customer engagement program we embarked on for this Revenue Proposal placed emphasis on using directly connected customers, stakeholders, and customer advocates. In this context and with the above objectives in mind, the following methods of engagement were identified as the most effective way to engage with our target audience:

1. Establishment of **Customer Advisory Panel** to guide our engagement with customers and to provide feedback on our plans.
2. **Briefing sessions**. The primary purpose of these sessions was to share information and provide context, then seek feedback on preliminary forecasts of revenue and expenditure plans and proposals.
3. **Deep-dive workshops.** These workshops were designed to rapidly immerse a group of customers and stakeholders into a specific set of topics, consider relevant evidence and seek their detailed feedback. While attendees were provided with extensive pre-reading materials, due to the often-technical nature of these sessions and complexity of the issues, these sessions targeted participants to a group of people with existing knowledge about energy and/or general consumer issues.
4. **Bilateral meetings.** Meetings to consult with advocacy groups and in some cases, their members, enabled the engagement to be tailored to meet the specific needs of the group, leading to more informed and relevant discussions. As this method tended to be time and resource intensive, it was better suited for engaging with a targeted group of customers and stakeholders.
5. **In-depth interviews**. As part of our on-going customer satisfaction research, we conduct in-depth interviews with a sample of 10 customers and stakeholders, including directly connected customers, other network businesses, generators and AEMO on a yearly basis to garner a better understanding of current performance and areas of improvement. These

interviews also provide an opportunity to seek and obtain general feedback on current and future expectations and priorities regarding our service in an environment of energy transformation, and more specific feedback about our preliminary forecasts of revenue and operating and capital expenditures.

3.5.2.2 Stakeholder identification

The TRR stakeholder engagement plan targeted the following stakeholder groups:

- **Directly connected and sub-transmission customers** – these are the consumers with the highest proportion of their electricity bills allocated to transmission, and so are likely to be the group most directly impacted by the review.
- **Victorian DNSPs** – the Victorian distributors pay for the use of the transmission network to supply energy to their customers and are responsible for planning augmentations to transmission connection assets.
- **Consumer and industry advocacy groups** – these bodies represent various end-user consumers and have historically been highly engaged in determination processes, including AusNet Services' previous transmission reviews and our current distribution regulatory reviews.
- **Generators** – generators own generation assets (including coal power stations, wind farms, gas-powered generators) connected to the transmission network. Generators pay non-contestable 'shared network' connection costs under individual connection agreements negotiated with AEMO.
- **AEMO** – as described above, in Victoria AEMO is a key stakeholder responsible for planning and procuring augmentations on the shared transmission network to meet forecast demand. AEMO pays for the use of the shared transmission network and passes its costs on to end-user customers.

As discussed below, all of these stakeholder groups are represented on the Customer Advisory Panel we established to provide stakeholder input to our plans.

3.5.2.3 Consumer Advisory Panel

The experience we gained from our approach to customer engagement in our electricity distribution regulatory review also influenced our decision to establish a Customer Advisory Panel for the TRR, rather than replicate the Customer Forum initiative. The reasons for this included:

- Due to the nature of transmission, where there is a small number of bigger customers connected directly to the network(e.g. distributors, generators and large businesses), it was possible to assemble a comprehensive group of informed representatives of those organisations, supplemented with key end user representatives.
- In contrast with distribution, where there are thousands of customers, we are regularly engaging and negotiating with the smaller number of direct connect transmission customers on key business and electricity issues.
- The Customer Forum was a trial developed in conjunction with the AER and the ECA. As the trial has not yet finished, an independent, external assessment of its effectiveness had not been completed.
- The resourcing requirements to run the Customer Forum were considerable. Given that the two regulatory processes were running in parallel, we concluded that neither us nor the AER were capable of establishing and running a second Customer Forum process without a significant increase in resources. We do not consider the additional resource requirements would be in the long-term interests of our transmission customers.

For these reasons, a Customer Advisory Panel, being a smaller, specialty body for engagement, was considered to be a better fit for the TRR (see Box 2 for details). This approach recognised the unique nature of transmission networks, including the need for very high reliability levels and a small number of large customers, as well as the different needs of large direct connect transmission customers relative to the smaller end-users served via the distribution networks.

Box 2: The Customer Advisory Panel

A core part of our commitment to targeted engagement on plans for the transmission network is the Customer Advisory Panel. The membership reflects the diversity of customers and stakeholders that depend on the transmission network, including both customers that directly engage with the network and residential and commercial customers that do not.

Member	Organisation	Member type
Gavin Dufty	St Vincent de Paul	Consumer advocate
Andrew Richards	Energy Users Association of Australia	Consumer advocate
Simon Elias & Aaron Tan	Air Liquide	Direct connect customer
Tennant Reed	Ai Group	Consumer advocate
Rodney Bray* & Rosh S	United Energy	Distributor
Bridgette Carter	BlueScope Steel	Direct connect customer
Mathew Creese**	Hydro Tasmania	Generator
Shelley Ashe	Energy Consumers Australia	Consumer advocate
Rudi Strobel	Jemena	Distributor
Elizabeth Carlile	CitiPower/Powercor	Distributor
Nick Eaton	Alcoa	Direct connect customer

* Until July 2020

** Until August 2020

The panel meets through a combination of online and face-to-face meetings on a quarterly basis, and otherwise as required. The purpose of the panel is to:

- Provide feedback on the design of our customer research and engagement program, and comment on findings and insights from this program;
- Represent electricity customers' needs, issues, and services and provide advice on how these should be addressed or incorporated in our plans; and

- Provide feedback on our draft plans, to ensure that they adequately reflect customer views and preferences.

3.5.2.4 Engagement topics

To ensure that the customer engagement activities focused on the issues that impact customer outcomes, we identified a set of engagement themes based on our learnings from our Customer Satisfaction program, CAP meetings and EDPR research activities. The key messages our customers communicated to us through these processes are:

- Customers are generally satisfied with current levels of reliability.
- Affordability is a key concern across all customer groups but there was also recognition that transmission capacity facilitates generator competition and can keep wholesale electricity prices lower.
- Improved relationship management is a key priority for large customers, distributors, and generators.
- There is a need to improve the connection process for new generators, which some generators have found to be complex and difficult to navigate.
- While the role of the transmission network has become critical to energy system transformation, the timing and cost of large network upgrades that will add capacity to the system need to be carefully managed to ensure customers pay no more than necessary. It was particularly apparent early on that there was real thirst for knowledge on the ISP from the large user groups.
- Customers are generally comfortable with our asset management approach, including our risk-based, economic assessment approach to asset replacement.

In response to the feedback we received from our customers, we identified the following themes for engagement. These themes were also validated with our CAP:

Table 3-2: Customer engagement themes

Engagement theme	Description
Energy affordability and pricing	Exploring the impacts of energy prices on customers connected to the transmission network and other stakeholders.
Energy reliability	Current reliability performance, reliability expectations, factors that influence reliability, proposed investment to maintain reliability.
Network stability and security of supply	Exploring emerging and increasing concerns, impacts on customers, proposed ISP projects.
Customer satisfaction and engagement	Customer service and engagement performance and expectations.
Service delivery pain points	Current service delivery performance, strengths, and areas for improvement.
Impact of energy system transformation	Impact of change on their organisation and the perceived or expected role of the transmission network in supporting this transformation.
The role of the transmission network	Current role, future role, and disruptive forces.

3.5.2.5 Consumer Engagement framework

Our approach to customer engagement is an iterative one, with the program evolving as insights from customers and stakeholders emerge. We adopted standards to engagement that are consistent with the AER's Consumer Engagement Guidelines and the IAP2 framework, which state that engagement should be:

(i) **Clear, accurate and timely communication**: recognising the different communication needs and wants of consumer cohorts and ensuring two-way flow of communication is possible.
(ii) **Accessible and inclusive**: recognising, understanding, and involving customers on an ongoing basis, not just at the time that our Revenue Proposal is being prepared.
(iii) **Transparent**: clearly identifying and explaining the role of customers and stakeholders in the engagement process.
(iv) **Measurable**: assessing the success, or otherwise, of our engagement activities.

3.5.3 Phase 2 Listen

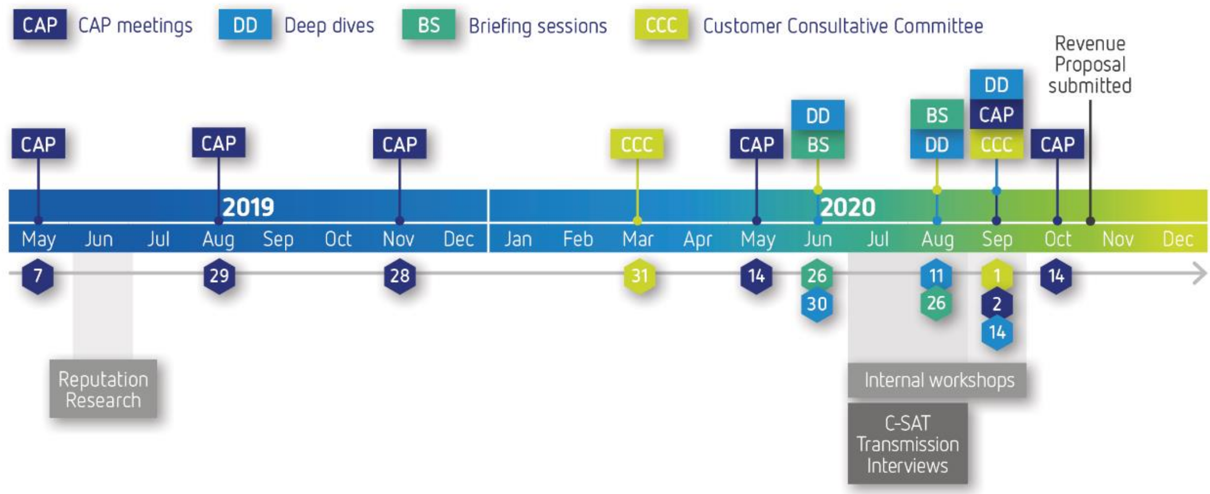
This phase involved engaging with customers directly connected to the transmission network, interested stakeholders impacted by AusNet Services, and wider stakeholder groups representing customers. To accommodate the needs of our respective customers and stakeholders, we conducted a range of engagement activities through the 'Listen' phase of our targeted engagement.

It is important to note that unlike many other transmission network businesses and our electricity distribution regulatory review engagement approach, we chose to not release a draft proposal for consultation in April 2020 as initially planned. Due to the impact of COVID-19, we felt it was prudent to not release a draft proposal to allow for adequate consideration of any impacts of the pandemic on our plans. Furthermore, as a result of COVID-19 lockdown restrictions, a majority of our 2020 engagement activities were undertaken online, as we were not permitted to meet in face-to-face.

Notwithstanding the challenges of the pandemic, we were able to adapt our engagement methods to continue to provide a highly targeted engagement program, offering a range of opportunities for customers and stakeholders to participate and provide feedback.

The figure below provides as overview of the activity timeline, with further details below.

Figure 3–1: Customer engagement timeline



Source: AusNet Services

3.5.3.1 Consumer Advisory Panel

Established in May 2019, the CAP met on six occasions over an 18-month period prior to the submission of this Revenue Proposal. During that period, sessions were attended by:

- panel members reflecting the diversity of customers and stakeholders that depend on the transmission network, including representatives of large customers, customer advocates, generators and the Victorian distribution businesses;
- AusNet Services representatives, including the managing director and members of our senior management team; and
- observers from AEMO, the AER and the AER's Consumer Challenge Panel.

In response to clear feedback from the CAP, we organised a joint sessions with AEMO to present on the ISP impacts on Victoria and undertook modelling of the price impacts of the ISP projects so that the CAP were fully informed about the total estimated transmission price in Victoria.

As previously highlighted, the CAP is advisory in nature and is not required to reach consensus on issues or make binding group decisions or submissions.

Set out below is an overview of each CAP session. Presentation materials are available on our website.

Table 3-3: CAP meeting focus areas

No.	Date	Overview
1	7 May 2019	Introductory session to provide background and contextual information to: • build common understanding about AusNet Services, our transmission network and customers, and the regulatory framework; • clarify the purpose, role and expectations of the CAP; • validate themes of customer feedback; and • guide the development of our customer engagement activities, including identifying the relevant stakeholders and the primary topics of relevance or concern.

No.	Date	Overview
2	29 Aug 2019	Primarily focused on consulting on external factors, challenges and feedback impacting the operating environment of our transmission business to: • debate and discuss how the current direction of Victorian and Federal Government Energy Policy and reviews by regulatory bodies impact the transmission network; • provide an opportunity to hear directly from AEMO on its 2019-20 Integrated System Plan; • build a common understanding of transmission system strength challenges; and • validate feedback on preliminary research findings from the 2019 Transmission Customer Satisfaction Survey.
3	28 Nov 2019	Early engagement on preliminary forecasts of capital and operating expenditure to inform development of a draft proposal and ensure customer views are reflected to the extent possible. In particular, we sought feedback on: • major station projects, asset replacement programs and ICT expenditure; • selection of the base year for opex forecasts and step changes.
4	14 May 2020	Primarily an update on the impact of COVID-19 on the regulatory review process and to seek feedback on our revised approach to engagement, including: • postponing or discontinuing publication of a Draft Proposal to allow AusNet Services time to properly consider the pandemic's implications for our plans; • an extension of three months for submission of our Revenue Proposal; and • proposed deep-dive workshop topics, rolling agenda for CAP meetings and other engagement activities.
5	2 September 2020	To seek feedback on how insights from Deep Dive Workshops #1 and #2 about proposed operating and capital expenditure respectively should be reflected in our Revenue Proposal. In particular, to agree on: • which step changes ought to be included in the Revenue Proposal, given stakeholder concerns around the need for a step change to fund some of these additional costs; and • how the network capital expenditure forecast should be profiled at an aggregate level to balance maintaining a reliable and safe supply with minimising deliverability risk.
6	14 October 2020	As the final CAP meeting prior to lodgement of our proposal, the primary purpose of this session was to summarise insights from the engagement program and provide an overview of Revenue Proposal positions, including revenue building blocks and price path. This recap included an update on the outcome of Deep Dive Workshop #3 regarding our proposed ICT expenditure and ground-wire asset replacement program.

3.5.3.2 Briefing sessions

In preparing our submission for the AER, we undertook two briefing sessions. These sessions were attended by a broad range of customers and stakeholders, including: CAP members, Victorian DNSPs, consumer and industry advocates, generators and AEMO. Sessions were also attended by AusNet Services' representatives, including senior levels of management.

The first briefing session was conducted ahead of the technical deep dives (see section below for more detail) and was designed to share relevant contextual information with attendees. This ensured they felt able to meaningfully engage and give their opinion during the deep dives. We also presented indicative revenues for early consultation and customer bill forecasts for discussion and feedback.

Heeding the feedback gathered through our ongoing (regular) engagement activities, we ran a joint briefing session with AEMO. The purpose of this session was to update attendees on the final Integrated System Plan (ISP) for 2020 and provide evidence around how ISP projects impact customers' bills.

Table 3-4: Briefing Session focus areas

No.	Date	Overview
1	26 June 2020	Introductory session to provide background and contextual information on: • The role of transmission in the energy system transition; and • Indicative revenue and customer bill forecasts.
2	26 August 2020	A joint session with AEMO to: • Discuss the final ISP for 2020, highlighting changes since the release of the draft ISP and implications for Victorian transmission customers; and • Discuss customer bill impacts of ISP projects.

3.5.3.3 Deep dives

Deep dives are a form of workshop that are designed to rapidly immerse a group of customers and stakeholders into a specific set of topics, consider relevant evidence and seek their detailed opinions and feedback.

Each of the identified customer and stakeholder groups outlined in section 3.5.2.2. were invited to these sessions and provided with extensive pre-reading materials. However, due to the often-technical nature of these sessions and complexity of the issues these sessions often attract and are best suited to those people with existing knowledge about energy and/or general consumer issues. You can find the specific attendees at each of our deep dives in Appendices 3B – 3D.

Set out below is an overview of each session and key outcomes.

Table 3-5: Deep Dive focus areas and outcomes

No.	Date	Overview	Outcome
1	30 June 2020	The first deep dive focused on elements of our proposed operating expenditure, specifically: • The choice of base year; and	• Maintaining 2020-21 as base year. • We will continue to address issues and questions raised by stakeholders on the cyber security step change.

		• Step changes relating to cyber security and transformer oil remediation works.	• Absorbing transformer oil step change to address affordability concerns.
2	11 August 2020	Components of our capital expenditure program were the focus of the second-deep dive. Four areas were discussed in detail: • Overview of indicative capex forecast and proposed major station projects; • Economic assessment framework for major station projects; • Major station project case studies; and • Capex profile and deliverability consideration.	• Agreed to explore ISP interactions at AST/AEMO briefing session. • Clarified which inputs are considered within the economic assessment framework and which are not. • Confirmed that the Revenue Proposal will provide detail on key assumptions. • Confirmed that we are required to explore non-network solutions as part of the RIT-T process. • Confirmed that the lowest net present value option is generally selected as the preferred option for major station projects. • Smoothing approaches to be explored.
3	14 September 2020	Our final deep dive explored elements of our Information and Communication Technology (ICT) expenditure and additional elements of the capital expenditure program. Specifically, we discussed: • Transmission specific ICT programs (intelligent network operations); • Ground wire replacement program; and • Forward engagement plan.	• Discussed technology operating expenditures for the current period versus the 2023-27 forecast. • Agreed to include recurrent expenditure in base case in our NPV analysis for the intelligent network operations program. • Noted that the ground-wire program may be subject to the RIT-T process.

3.5.3.4 Customer satisfaction interviews

The 2020 iteration of our annual transmission customer satisfaction qualitative interviews ran between June and August 2020. These interviews were conducted online (an artefact of COVID-19 restrictions at the time) and were undertaken by our Customer Research Manager. A senior member of the regulatory team attended all interviews to ensure any technical questions relating to the transmission revenue reset could be answered. Where necessary, a senior manager also in attended.

In total, we spoke with 13 customer and stakeholder groups, including:

- 3 directly connected customers;
- 2 renewable generators recently connected into the transmission network;
- 3 Victorian DNSPs;
- 4 consumer and industry advocate organisations; and

- AEMO.

3.5.3.5 Internal engagement

We recognise the importance of ensuring that key internal stakeholders understand and are able to action the insights that we learned from our customers and stakeholders. To ensure this, we ran internal de-briefing sessions after each deep dive session to discuss what we heard and to ensure the feedback received from customers was interpreted consistently across our organisation. These internal briefings were also important in enabling us to refine our approach to the remaining deep dives to ensure continuous improvement in our engagement approach.

Set out below is a summary of the key decisions and outcomes from our project team working group de-briefing sessions:

Table 3-6: Internal engagement outcomes

No.	Date	Purpose	Outcome
1	29 Jul 2020	To discuss implications of Deep-dive workshop #1 for our Revenue Proposal.	Remove two step changes from Revenue Proposal and absorb the cost of these initiatives.
2	Throughout August	To discuss capex forecasting implications of Deep Dive #2 outcomes.	Reprioritised a number of major stations rebuild projects to smooth the capex profile and reduce deliverability risks as agreed in Deep Dive #2.

3.5.4 Phase 4 Post-lodgement engagement

We plan to undertake intensive engagement with customers and stakeholders on our plans for the transmission network over the 2023-27 regulatory control period after we submit our initial regulatory proposal to the AER. The primary purpose of this engagement will be to explain our proposal and any changes to our plans in response to new information, including updated AEMO demand forecasts reflecting the impacts of COVID-19.

3.5.4.1 Engagement methods

During this phase, we plan to undertake the following engagement activities:

Table 3-7: Post-lodgement engagement

Timing	Method	Summary
Nov – Feb 2021	Bilateral meetings	Recognising that the customers and stakeholders we want to engage with are in high-demand and have limited availability, we will take a bespoke approach to our engagement activities. Specifically, we plan to hold a series of one-on-one sessions with customers and stakeholders scheduled at a time that suits them. We have, in fact, scheduled many of these discussion in the coming months.
Dec 2020	Customer Consultative Committee	We will present an overview of the submission at our December CCC meeting.
Feb 2021	Briefing session	A forum for engaging with customers who are directly connected to the transmission network, customer representatives, and other interested stakeholders to explain the implications of new information for our plans and to agree focus areas for further deep dives.
April - May 2021	Additional deep dives	We will hold deep dive workshops to seek feedback topics of interest to stakeholders.
June 2021	CAP	Purpose of this meeting will be to agree on how new information and insights from post-lodgement engagement activities should be reflected in our Revised Revenue Proposal, due in September 2021.

3.5.4.2 Output

We intend to publish a summary report of the themes discussed and feedback received from customers and stakeholders following post-lodgement engagement.

3.6 How we have responded to customer and stakeholder feedback

The following section provides a summary of the key matters raised through our ongoing and targeted customer and stakeholder engagement activities and the manner in which these have been taken into consideration in our Revenue Proposal and in our operating decisions. This feedback has been consolidated and summarised based on our engagement themes.

3.6.1 Energy affordability and pricing

Total energy prices have risen considerably in the last 5 years with significant impacts across all customer segments. In particular, these increased costs can affect the viability of many large businesses.

While transmission prices have declined in real terms over the last 5 years, we recognise that as part of the supply chain we must listen and respond to customer preferences. Under our plans, transmission prices are expected to continue to fall. Our plans also complement the ISP projects to ensure wholesale competition is maximised and that the cheapest generation can be traded in

Victoria and, by providing a reduction in our component of transmission charges, will help to offset the cost of these investments.

Transmission investment is based on an assessment of efficient costs versus customer benefits, such as the value placed by customers on reliability. By pursuing only the investment opportunities that deliver the greatest customer benefit at the most efficient cost, we ensure that customers are only paying for prudent and efficient costs. Chapter 4 provides further information on our economic assessment framework and how this ensures that our capital expenditure forecast reflects efficient costs.

As part of developing our operating expenditure forecast, we have taken several specific actions to address our customers' affordability concerns. Many customers requested greater bill transparency. For many, they are seeking a more nuanced breakdown of their TUoS charges to better understand what the drivers of cost are and where they might have the capacity to reduce their transmission charges. In addition, we have accounted for forecast productivity improvements and we are absorbing two step changes, which has collectively reduced our opex forecast by $8 million. Further information on our operating expenditure forecast is available in Chapter 5.

3.6.2 Supply reliability

Customers have told us they are generally satisfied with current reliability levels. However, they have also said that failures in reliability can lead to significant production losses and equipment damage, demonstrating the importance of reliable transmission services in the next regulatory period. Customers have also told us that voltage dips can result in significant time, product, and energy losses.

While it is acknowledged that 'things will happen from time to time', customers would like greater transparency about the causes of network events when they do occur. Specifically, customers expect that we would contact them following an incident and explain what happened and what we are doing to prevent such events from occurring again. The introduction of a dedicated Customer and Industry Engagement team is intended to help bridge this information gap.

On planned works, customers have voiced a desire to better align the timing of our planned works with their maintenance schedules, avoiding the need for multiple outages. It is customers' expectation that we better accommodate their planned outage preferences in the future.

To ensure continued reliability, we have commenced a program of works that is designed to maintain and upgrade the specific assets servicing some our largest transmission customers.

Our capex forecast has been developed to maintain the strong performance and high reliability that our customers expect of the network, in line with the updated VCR values published by the AER in December 2019. We have also prioritised major station rebuild projects using a customer supply risk impact measure (i.e. the risk to the customer of supply being lost due to an asset failure) as a key input.

We are also investing ways to improve communication about and the management of planned and unplanned outages. While transmission outages are rare, this is a relatively low-cost way to improve our transmissions customers' experience.

Finally, customers would like to understand what we are doing to safeguard the security of the network in the future. Approximately one quarter of our proposed capital program relates to projects that will maintain reliability at critical switching stations that support the interconnected transmission system and, therefore, are vital to overall system security.

3.6.3 Customer satisfaction and engagement

Customer feedback confirms that we have significantly improved the way we serve and engage with our transmission customers. Customers have noticed a shift in our appetite to engage with them on the 'tough' issues and have open and honest dialogue over the past two years. They have suggested that more attention could be directed at better managing strategic relationships with customers. As noted above, our dedicated Customer and Industry Engagement team have been appointed to provide a direct contact point for large users and to proactively address customer concerns and issues.

3.6.4 Service delivery pain points

Feedback from customers suggests that services levels have improved in recent years. Specifically, they have told us that it has become easier to contact us for both operational and strategic advice and guidance. Regardless of this improvement, however, they have stressed that there is still considerable opportunity for further improvement. Some areas where they would like to see improvement is in a (i) greater willingness to negotiate on elements of the contract (ii) more accurate cost estimates and (iii) more transparent communications throughout the process (see Appendix 3A for more details). We are committed to better understanding how our actions impact customers and the specific 'pain points' that they feel. Therefore, we have commenced discussions with generators seeking to connect to the network. We are also investing to improve the communication and management of planned and unplanned outages.

3.6.5 Impact of energy system transformation

There is a need to invest in understanding customers' current and future needs, including building the network to ensure there is sufficient capacity to host renewable generation. Customers, particularly those directly connected to our network, voiced concern around the ISP and the potential reliability impacts associated with the implementation of these projects. For example, customers indicated concerns with the potential scheduling impacts of any planned outages that will be needed to connect renewable generators into the transmission network. Understanding how AusNet Services and AEMO intend to mitigate any potential impacts was identified by customers as being of paramount importance.

As noted above, our proposal will help to offset the future costs of the major transmission upgrades planned for Victoria that are set out in AEMO's ISP. Even after adding the indicative cost of expected Victorian ISP investments to the revenues outlined in our proposal, we are forecasting real revenue reductions (see Chapter 13 for more details).

3.6.6 The role of the transmission network

It is pleasing that AusNet Services is perceived by customers and stakeholders as having a significant role to play in the transformation of the energy sector that is currently underway. However, many customers consider that we could act more proactively, becoming the 'trusted advisor' for parties seeking to connect into the network and for other customers and stakeholders. Our ability to successfully collaborate and co-operate with AEMO, in their capacity as Victorian planner, will be critical in this transformation.

3.7 Supporting documents

The following supporting documents are relevant to this chapter:

- Appendix 3A – Customer Satisfaction Interviews Summary Report.
- Appendix 3B – Deep Dive Summary Report 1.

- Appendix 3C – Deep Dive Summary Report 2.
- Appendix 3D – Deep Dive Summary Report 3.

4 Capital expenditure

4.1 Key points

- Our capital expenditure (capex) program is required to maintain the safe, reliable and secure energy supply our customers expect of us. It reflects the growing importance of network infrastructure in areas where significant renewable generation is being established, and the critical importance of reliable transmission services to Australia's future electricity system. Importantly, the capex forecast has been developed based on AusNet Services' economic approach to planning which aims to minimise the expected lifecycle cost of transmission assets.
- We are proposing capital expenditure (capex) of $796.2 million ($M, real 2021-22) for the next regulatory period to maintain a safe, reliable and secure network. This is $64 million or 9% higher than the expected capex spend in the current regulatory period.
- Over half of our total forecast capex relates to major projects at terminal stations where, based on asset condition, it is economic to replace assets during the next regulatory period. Approximately 50% of this major stations expenditure is for works at switching stations that form the backbone of Victorian transmission and is required to maintain the security of the national transmission system and competitiveness of the National Electricity Market (NEM). These assets are also crucial to the transition to a lower carbon future, not least as they will allow us to efficiently integrate utility scale renewable generation.
- Around one-third of our total forecast capex is for condition-based asset replacement programs that are needed to maintain reliability and safety. This includes assets (many of which were installed in the 1960s and early 1970s), such as conductors, ground wires and power transformers reaching the end of their technical life.
- Through consultation with our customers, we have applied a top-down smoothing adjustment to our network capex to manage deliverability risks while also ensuring our customers' expectations of reliable and affordable supply are met. This adjustment has resulted in the deferral of expenditure for some major station projects, without compromising the safety of our employees and the community.
- Higher technology expenditure is also needed, reflecting the transmission network's share of our company-wide technology strategy, including with respect to meeting new cyber security regulatory obligations. Our Information and Communications Technology (ICT) proposal represents around 10% ($83.8 million) of our total proposed capex.

4.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 4.3 provides a summary of our capex forecasts;
- Section 4.4 outlines our key inputs and assumptions;
- Section 4.5 explains how we have taken the feedback from customer engagement into account;
- Section 4.6 outlines our forecasting approach;
- Section 4.7 presents information on our benchmarking performance;
- Section 4.8 describes the main variations in forecast capex from historic capex;
- Section 4.9 outlines our major stations capex;

- Section 4.10 outlines our replacement capex;
- Section 4.11 outlines our safety, security and compliance capex;
- Section 4.12 outlines our information and communications capex;
- Section 4.13 outlines our other non-network capex;
- Section 4.14 considers deliverability;
- Section 4.15 explains why our capex forecasts satisfy the National Energy Rules (NER); and
- Section 4.16 sets out the supporting documents for this chapter.

4.3 Summary of our capital expenditure forecast

Amidst the unprecedented changes occurring in the energy system, transmission networks play a critical role in ensuring the reliability, strength and security of the system and the increased competitiveness of the wholesale market. In particular, transmission networks link multiple generator supplies so that supply can be maintained in the event of an unexpected failure of a generator or a link. This improves the resilience of the overall system and helps avoid interruptions to customers' energy supply. However, it also means that when multiple elements of the transmission system fail, the consequences can be widespread.

In this context, our proposed capex forecast seeks to maintain the reliability, security and safety of the Victorian transmission network in the next regulatory period, while also balancing our customers' affordability concerns. The condition-based, economic replacement of deteriorated assets, which present a supply risk to the interconnected transmission system, is central to these plans. Our forecast includes several replacement projects at switching stations that form the backbone of the Victorian transmission network or support interconnectors.

We are proposing capex of $796.2 million for the forthcoming regulatory period. This is 9% ($64 million) higher than the capex we expect to incur in the current regulatory period, and in line with our current period allowance of $790.4 million. The increase on our current period expected spend largely reflects:

- Higher expenditure to replace terminal station assets and ground-wire and insulator line assets, based on their condition; and
- Higher technology expenditure, including cyber security investment to comply with an anticipated change in our regulatory obligations.

Consistent with the current regulatory period, major station projects account for almost half of the total capex forecast. Asset replacement and ICT programs account for most of the remaining half.

The table below sets out our proposed capex forecast by driver. Each of these categories is explored in sections 4.9 to 4.13.

Table 4-1: Overview of proposed capex ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Major Station Projects	101.7	105.1	102.3	72.7	42.4	**424.2**
Replacement Programs	45.0	44.1	42.6	37.2	44.6	**213.4**
Safety, Security and Compliance	8.9	8.2	10.4	16.1	10.7	**54.2**
ICT	18.0	18.4	19.4	15.0	13.0	**83.8**
Non Network	3.7	4.3	4.9	3.8	3.9	**20.6**
Total	**177.4**	**180.0**	**179.5**	**144.7**	**114.5**	**796.2**

Source: AusNet Services

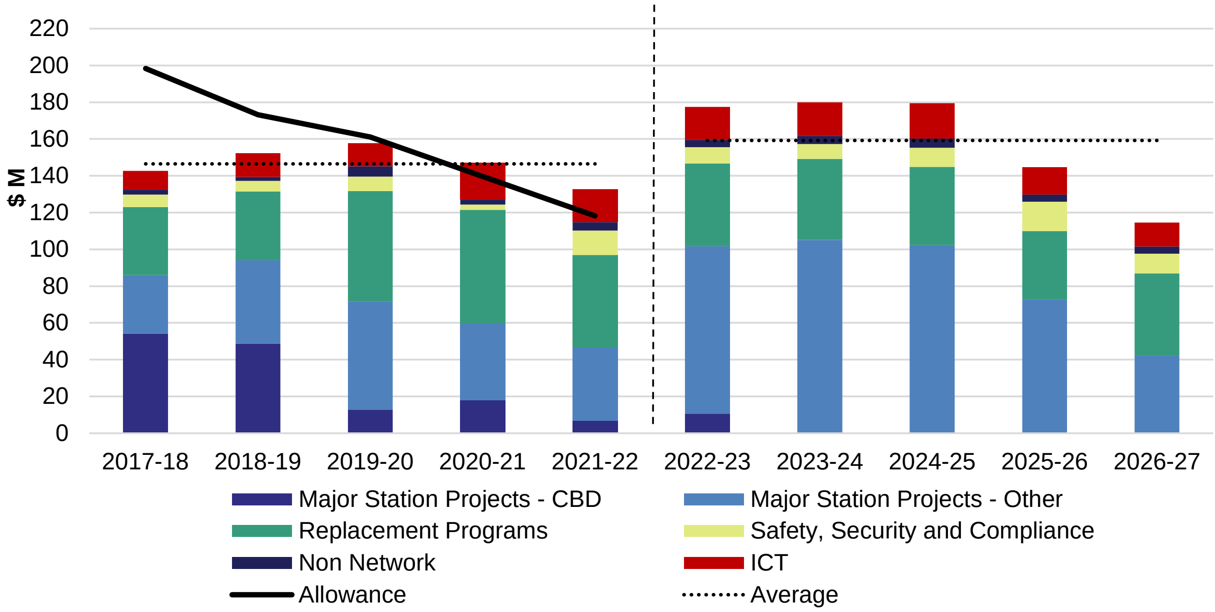
In developing our capex forecast, we have had regard to a range of factors, including:

- The condition of our asset base, which is regularly assessed through a combination of visual inspection, thermal imaging and increasingly sophisticated and more efficient methods such as high-resolution aerial photography, and drives all of our asset replacement decisions;
- The transition that is currently occurring in the energy market, the increasingly complex environment that we are operating within and the important role transmission networks are playing to maintain system strength and security in this environment;
- Stakeholders' views on key aspects of our capital program, including our proposed major stations projects, the profile of the overall capex forecast and our technology programs, canvassed in several Deep Dive workshops held between July and September 2020;
- The capital expenditure objectives outlined in the NER; and
- Interactions between our proposed projects and the major augmentation projects planned for Victoria as part of AEMO's Integrated System Plan (ISP), the Victorian Annual Planning Report (VAPR) and the Distribution Annual Planning Report (DAPR).

Our capex forecast for the next regulatory period, as detailed in this chapter, represents a prudent and efficient level of capex that will ensure the continued delivery of safe, reliable and secure energy services to our customers.

Figure 4–1 below compares our capex forecast with the allowance and expenditure for the current regulatory control period.

Figure 4–1: Historical and forecast capex ($M, real 2021-22)



Source: AusNet Services

Current period capex expenditure

Our expected capex in the current period is $732.2 million. This is 7% ($58 million) below the allowance approved by the AER. The expected expenditure outcome reflects:

- $358.1 million for major station projects (including the two Central Business District (CBD) terminal station rebuilds). This is $35.8 million (11%) above the approved major station allowance. Key drivers of this increase are higher than expected expenditure for the

Fisherman's Bend Terminal Station refurbishment project, and inclusion into the program of two unforeseen projects that were not reflected in the allowance approved for the current period:

- Loy Yang Power Station and Hazelwood Power Station 500 kV circuit breaker (CB) replacement stage 1 project, required due to increased criticality as a result of the sudden closure of Hazelwood Power Station; and
- Replacement of 500 kV circuit breakers at Heywood Terminal Station, given the forecast reduction in supply reserves in Victoria because of the closure of Hazelwood Power Station. The power station retirement resulted in Victoria becoming more dependent on power imports via interconnectors with South Australia, Tasmania and NSW.
- These increases are, however, partially offset by the economic deferral of several other projects, including:
  - Templestowe Terminal Station B2 transformer and 66 kV CB replacement, which was deferred into the forthcoming regulatory period due to lower risk levels resulting from lower VCR and demand forecasts; and
  - East Rowville Terminal Station B1, B3 & B4 transformer replacement, which is now being delivered as a series of staged replacement projects, following a reassessment of the most economic solution. Stage 1 is underway and will replace one of the three transformers as well as some critical switchgear. Stage 2, which will replace the remaining two transformers and switchgear, has been included in our capex forecast for the forthcoming period.

- $246.2 million for asset replacement. This is $24.3 million (9%) below the AER's regulatory allowance. This reflects lower than expected expenditure for circuit breaker and disconnector replacements, which has been partly offset by higher than expected expenditure for transformer replacements;
- $36.8 million for security and compliance. This is $40.5 million (52%) below the AER's regulatory allowance and reflects lower than forecast expenditure across several areas, including safe access to power transformers, infrastructure security and tower fall arrests (the latter of which is due to adopting a new approach for installing fall arrests and introducing different inspection techniques);
- $73.5 million for ICT and other non-network. This is $18.4 million (20%) below the AER's regulatory allowance and reflects a combination of project efficiencies and reprioritisation of some projects. Further information on the drivers of the expected ICT underspend is provided in Appendix 4C.

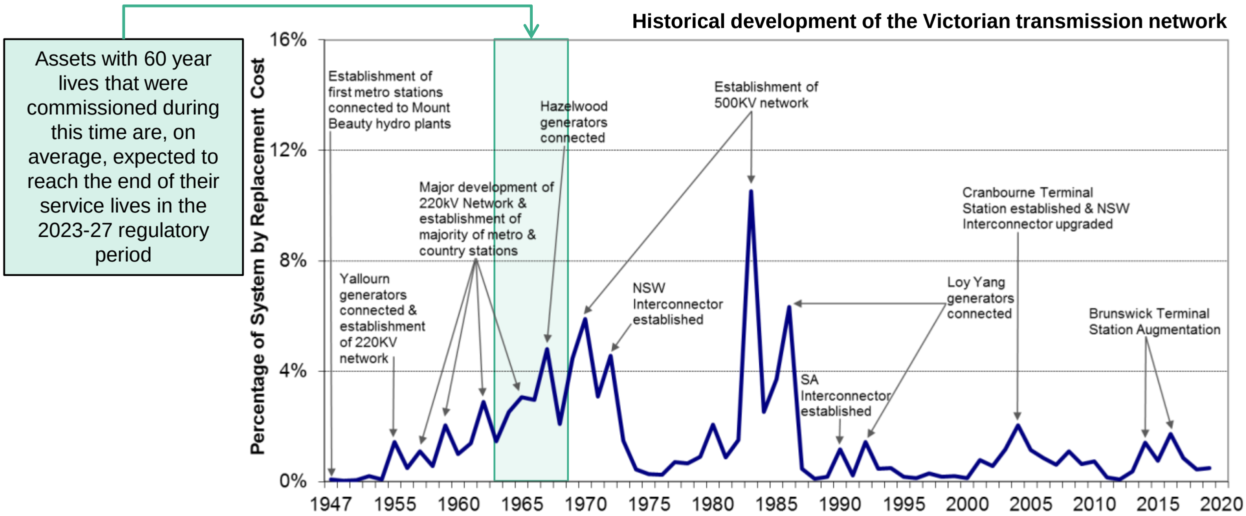
We have also delivered several projects, not forecast at the previous review, that are crucial to efficiently integrating renewable energy into the system including critical works on the network communications loop in North West Victoria.

The underspend in total capex expected in the current regulatory period represents savings that will be passed on to our customers because of reprioritisation or finding more efficient ways of meeting our obligations. We have efficiently delivered the works program, substantially as proposed for the current regulatory period, and implemented further critical projects, all whilst containing our costs to within the AER's expenditure allowance. This benefits customers in the forthcoming and subsequent regulatory periods through lower RAB growth than would otherwise be the case.

Forecast period capital expenditure

As shown in the figure below, a significant portion of the transmission network was established between 1955 and 1970. Assuming an average asset life of 60 years, a substantial share of our assets are expected to reach the end of their useful lives over the next regulatory period.

Figure 4–2: Historical development of the Victorian transmission network



Source: AusNet Services

Note: The Y-axis measures the undepreciated value of all historical development and augmentation of the network, converted to a common real dollar term and expressed as a percentage of the replacement value of the network

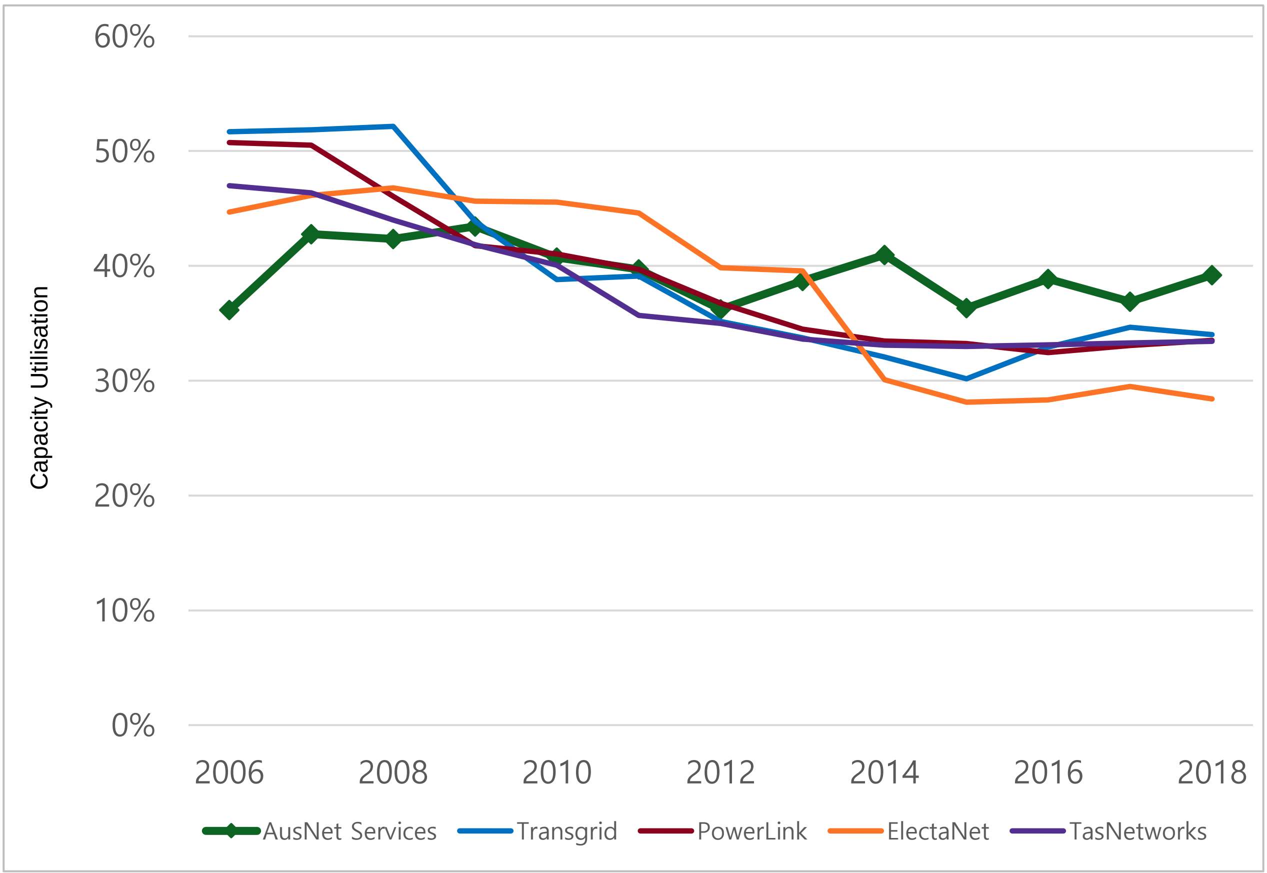
While we replace assets based on condition rather than age, because condition is correlated with age, our ageing asset base is a key driver of the increase in capex being forecast for the next regulatory period.

However, we do not expect future replacement expenditure will perfectly mirror the original investment profile, in terms of timing and cost. This is because effective asset management, based on condition rather than age, enables AusNet Services to identify opportunities to efficiently defer the replacement of some assets past their design life. This maximises the service life of existing assets and minimises long-term costs to customers.

To ensure we only invest where and when it is efficient, we rely on a probabilistic planning approach. Other jurisdictions use a deterministic planning approach which is lower risk but higher cost. Our approach only replaces assets when the risk cost, or impact, of an asset failing exceeds the cost of replacing the asset. To measure this impact, we consider a range of factors, including the value placed by customers on a reliable supply, as measured by the VCR, and the safety consequences of asset failure. Our plans do not include the replacement of the assets on our network where the risk cost is less than the cost of replacement, some of which are either very old or in a deteriorated condition. That is, we deliberately do not address the risk associated with these assets because the cost of doing so is higher than the benefit from the risk reduction.

While this approach leaves some residual risk on the network, it ensures that our assets are run as long as possible whilst maintaining the reliability and safety of the network at a standard that is acceptable to our customers, the community and our employees. This is illustrated by Victoria's higher asset utilisation shown in the figure below.

Figure 4–3: Transmission network capacity utilisation in the NEM



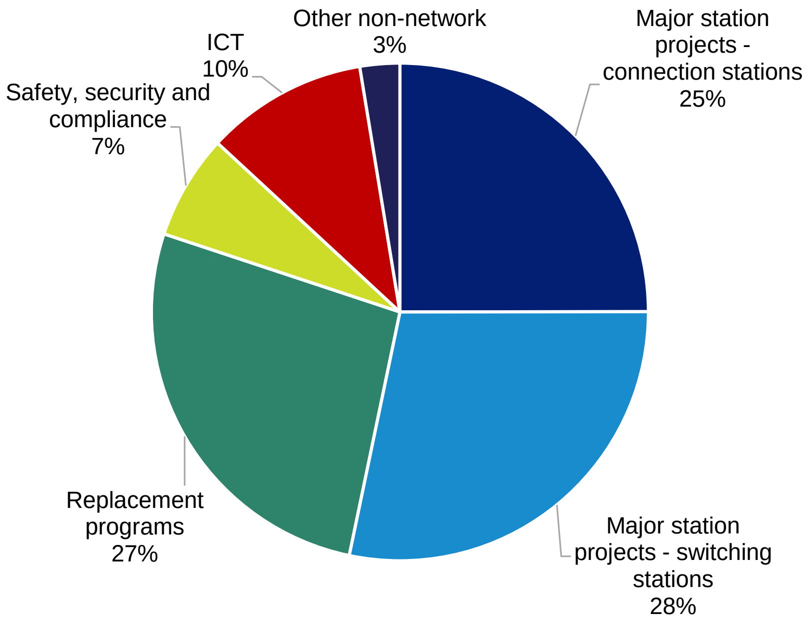
Source: AusNet Services

Our probabilistic planning approach also means there is very limited flexibility in our plans to accommodate delays in the replacement of the deteriorated assets we have identified as needing replacement during 2023 to 2027. To do so would risk network reliability and safety dropping below the standard that is acceptable to our customers, the community and our employees.

Our economic approach to investment planning is discussed further in section 4.6.

The composition of our forecast capex is shown in the figure below. As no augmentation is included in our plans, AEMO's ISP is not directly relevant to this Revenue Proposal. However, AusNet Services and AEMO work together to integrate replacement and augmentation projects for the Victorian transmission network, to ensure any potential cost efficiencies are achieved.

Figure 4–4: Composition of forecast capex 2023-27



Source: AusNet Services

Unlike the current regulatory period, where several large, complex major CBD rebuilds accounted for a significant component of our expenditure, around one-quarter of the total capex forecast is for replacement works at switching stations that form the backbone of the Victorian transmission network or support interconnectors. These stations are important nodes in the national, interconnected transmission system and the dependable reliability of assets critical to reliability and security of the power system. This criticality has fundamentally increased since the closure of Hazelwood and Victoria moving from being a net exporter to net importer of electricity.

The remaining major stations capex is for asset replacement at terminal stations where distribution networks connect to the transmission network. For all of these major station projects, we have conducted comprehensive cost-benefit analysis to ensure the proposed asset replacement activities are economic and, therefore, in the long-term interests of customers.

Outside our major station rebuilds, our replacement programs involve numerous programs of work, including the replacement of components such as insulators, ground wires and circuit breakers. This is required to manage the unacceptable reliability and safety consequences of deterioration in asset condition, consistent with the ageing nature of the asset base.

Our approach to these typically 'high volume, low value' assets involves visual assessment of asset condition, with analysis and modelling then applied to assess the probability and consequence of asset failure and, therefore, whether it is economic to replace the relevant assets.

Our ICT program consists of eight programs, seven of which are the transmission allocation of corporate-wide ICT programs that were approved by the AER in its recent draft decision for our electricity distribution network.[38] We have proposed one TRR specific program, the $16 million Intelligent Network Operations program. By modernising key operational and outage planning capabilities, this program will allow us to support and maintain the reliability and security of the Victorian transmission network and field operations in an increasingly complex energy market where scheduling planned outages for project delivery and maintenance works is becoming increasingly challenging due to deteriorating system security on the Victorian transmission

[38] ICT programs that also formed part of our EDPR proposal include: (1) Corporate Communications; (2) Technology Asset Management – Applications; (3) Technology Asset Management – Infrastructure; (4) Corporate Enablement; (5) Workforce Collaboration; (6) Information Management; and (7) Cyber Security.

network. Consistent with the AER's new approach to assessing ICT expenditure,[39] we have identified which of our proposed ICT programs (and components of individual programs) are recurrent or non-recurrent expenditure.

AusNet Services' investment decision-making practices are supported by a robust project governance framework, which incorporates continuous improvement to ensure projects are delivered at lowest efficient cost, and that replacements can be deferred where this is the most efficient risk-based outcome. This framework, which has been used to develop our capex forecast, is consistent with the approach taken for budgetary, planning and governance processes used in the normal running of our business.

The capital expenditure forecast has been subject to rigorous internal testing to ensure that it is analysed, reviewed and finalised appropriately. A due diligence process has been followed prior to sign-off of the submission. This process includes following a Submission Assurance Plan, which focuses on information management and internal quality assurance, including regulatory model review.

4.4 Key inputs and assumptions

The key inputs and assumptions underpinning our capex forecast include:

- Compliance with laws, codes and standards;
- Demand forecasts;
- Value of customer reliability;
- Market impact;
- Condition reports;
- Failure risk ratings;
- Unit rates;
- S-curves;
- Cost escalators;
- Capex efficiency;
- Capitalised overheads;
- Capex/opex trade-offs;
- Network support costs; and
- Affordability and deliverability.

Further details on these inputs and assumptions are summarised in the table below. More detailed information is available in our Expenditure Forecasting Methodology and Appendix 4B.[40]

[39] As set out in AER, *Guidance Note - Non-network ICT capex assessment approach for electricity distributors*, 2019.

[40] AusNet Services, *Expenditure Forecasting Methodology - Transmission Revenue Reset for the Regulatory Control Period beginning 1 April 2022*, March 2020.

Table 4-2: Summary of inputs and assumptions

Input / Assumption	Description
Compliance with laws, codes and standards	We must comply with various regulatory obligations and legislative requirements. Some of these requirements result in substantial expenditure on system protection and communication assets, which are aimed at protecting our network and the rest of the transmission system in the event of a fault. We must also comply with various occupational health and safety and physical security regulations.
Demand forecasts	While we are not responsible for planning network augmentations, we use demand forecasts to help plan when our assets should be replaced in order to maintain reliable supply. Demand forecasts are a key factor in determining the consequences of an asset failure and, in turn, the economic benefit of replacing the asset. We have used AEMO's 2019 forecasts to develop our capex forecast, which have been provided as Appendix 4D.[41] To take account of COVID-19's impacts on forecast demand, we intend to have regard to AEMO's 2020 forecasts when developing our Revised Revenue Proposal's capex forecast. However, after reviewing AEMO's draft 2020 forecasts, we are concerned with how DER growth has been accounted for. Specifically, we are concerned that AEMO has significantly overestimated the impacts of rooftop PV growth on forecast maximum demand in several of Victoria's growth areas. Upon finalisation of AEMO's 2020 forecasts, we intend to undertake an assessment of whether these forecasts are fit for purpose for our Revised Revenue Proposal. We will consider this issue further (including through further engagement with our customers and stakeholders) during the review process.
Value of Customer Reliability (VCR)	The VCR is a key input into how we determine when to replace assets on our network. The VCR represents the monetary value different types of customers place on having access to a reliable electricity supply. Our capex forecast uses the December 2019 VCRs published by the AER.[42]
Market impact	The impact on wholesale prices when outages on the transmission network constrain the lowest cost generators from supplying energy to the market.
Asset condition	Asset condition is a key input to developing our replacement expenditure forecasts. We measure asset condition using an asset health index, on a scale of 1 (as new) to 5 (advanced deterioration). In general terms, the poorer the condition of the asset, the greater the risk of failure.
Failure risk ratings	Based on asset condition data for individual assets or classes of assets, we assign a failure risk rating. This reflects both the probability of the

41 As set out in AEMO's Transmission Connection Point Forecast, published in November 2019. Note that these are the latest forecasts available and predate any impacts arising because of the COVID-19 pandemic. AusNet Services will review the implications of updated forecasts when available (expected November 2020).

42 In developing the values, the AER surveyed over 9,000 residential and business customers of various sizes and industries across eastern and south-eastern Australia and the Northern Territory. The VCRs developed by the AER are specific to climate zones and locations (regional or urban). We have used the updated VCR in developing our network investment plans, reflecting customers' current preferences regarding both price and reliability.

Input / Assumption	Description
	asset failing and the consequences that failure would have on network safety and reliability. This informs what and when we need to replace assets, while also ensuring a safe and reliable network at the lowest cost to customers.
Unit rates and project cost estimation	The unit rates used to derive project cost estimates have been established from internal standard costs, which reflect data on the actual costs of projects delivered. Estimates are subject to reviews and a sign-off process based on consistent clear lines of responsibility and accountability that ensure costing standards and controls are applied to the estimates relied upon for developing the capex forecast.
S-curves	S-curves are used to define the profile and timing of expenditure over the term of a major capital project. The S-curves we apply reflect actual historic experience.
Cost escalators	For internal labour, we have assumed a real increase in labour costs of around 0.80% per annum, which reflects the average of two expert forecasts of the EGWWS WPI. Our proposed internal labour cost escalators are discussed in more detail in Chapter 5. Materials costs are assumed to increase at the same rate as inflation. Our approach to escalating our external labour costs is discussed in the section below.
Capex efficiency	With a large portfolio of projects undertaken over the regulatory period there is opportunity to optimise the work plan to avoid overlaps. Considering AusNet Services' strong culture of continuous improvement we have reviewed our forecast projects and programs to identify any overlaps. This has resulted in a top-down adjustment of $2 million to the network capex forecast. We also worked with our customers to develop a portfolio optimisation approach, based on the prioritisation of supply and market impact risk, to smooth our forecast and minimise deliverability risk. The deliverability of the forecast is discussed further in section 4.14.
Capitalised Overheads	Our forecast pool of capitalised overheads reflects our total corporate and network overheads that we have capitalised in accordance with our capitalisation policy. Our capitalisation policy was amended in April 2019 to Accounting Standard AASB 16, which treats operating leases as 'Right to Use' (capital) assets. Our forecast of the fixed pool of overhead costs is, on average, $8.2 million per annum over the 2023-27 regulatory period. This is in line with annual average actual/expected overheads in the current regulatory period of $8.0 million. The pool of capitalised overheads attributed to the transmission business is allocated to the different asset categories according to our internal accounting policies.
Capex/opex trade-offs	As part of ensuring that our capex forecast reflects only efficient costs, we have sought to identify opportunities to substitute opex for capex and in doing so, reduce total long-run costs to customers. For example, we intend to address a corrosive sulphur oil issue that is affecting our

Input / Assumption	Description
	transformer fleet using an opex solution, avoiding the need for a more costly capex program to replace the affected transformers. We also elected to absorb this step change in response to customer feedback, resulting in customers benefiting immediately from the productivity improvements required to fund this expenditure. This is discussed further in Chapter 5.
Network support costs	Rapid changes to the generation mix, from traditional to renewable sources, is compromising the system security of Victoria's transmission network. This is also reducing the window of opportunity to undertake planned outage activities and maintain our assets. These windows may reduce to such an extent that AusNet Services cannot adequately maintain its assets unless AEMO, in its capacity as the Victorian transmission planning authority, augments the network. AEMO has advised AusNet Services that if we take outages outside of the windows approved by AEMO (in its capacity as the system operator), even if doing so would be advantageous from a market impact perspective, then we must procure network support in order to ensure AEMO can maintain system security for the duration of the outage. We are currently conducting a full costing exercise with a network support provider to ascertain the full cost of the associated network support that are likely to be required in the upcoming regulatory control period. As the expected network support costs remain uncertain at the time this proposal is submitted, we have not included this expenditure in our capex forecast at this time. We consider the network support pass-through mechanism under clause 6A.7.2 of the NER is a more appropriate mechanism for recovering these costs. We are working with the AER to clarify how this pass-through mechanism can be applied in these circumstances and may revisit this issue – including the extent to which adjustments to our expenditure forecasts are needed - in our Revised Revenue Proposal.
Affordability and deliverability	Drawing on our experience as the first Australian utility to trial the NewReg process for our electricity distribution reset,[43] we have consulted with our customers on affordability and deliverability when preparing our transmission plans. We have: • Established a Customer Advisory Panel, and engaged with customer stakeholders more broadly through several capex Deep Dive workshops held in in August and September 2020, to obtain feedback on our customers' preferences and discuss how we aim to balance affordability with reliability in developing our plans; • Sought feedback on the price impact of our capex proposal from transmission customers and end-use consumers;

[43] https://www.aer.gov.au/networks-pipelines/new-reg.

Input / Assumption	Description
	• Considered the deliverability of our proposed program, in terms of physical and capital resource requirements and scheduling of works; and • Consulted with our customers on options to manage the deliverability of our proposed program, having regard to the price and risk impacts of deferring projects to minimise deliverability risk.

Source: AusNet Services

4.4.1 External cost escalation

In developing our capex forecast we have applied a forecast of Construction WPI to the cost of external (contracted) labour. We obtained this forecast from BIS Oxford Economics, which also prepared one of the EGWWS WPI forecasts we have applied to our opex forecast. These forecasts, which have been provided as Appendix 5D, are consistent with the updated WPI forecast we obtained for our electricity distribution Revised Regulatory Proposal. These forecasts were prepared in October 2020 and reflect some impacts of COVID-19 to June 2020.

For this Revenue Proposal the forecast is a placeholder that will be updated in our Revised Revenue Proposal. In particular this forecast does not capture the later economic impacts of COVID-19, such as the imposition of a second Stage 3 lockdown and subsequent Stage 4 lockdown declared in parts of Victoria from early July, nor the impact of any yet-to-be announced policy stimulus measures which may be included in the November Victorian Budget. To account for new information, including the ongoing impacts of COVID-19, we will commission an updated forecast from BIS Oxford prior to submitting our Revised Revenue Proposal.

We consider the Construction WPI is the best available forecast of growth in the costs of our contracted labour during the forthcoming regulatory period. This is because we expect the labour component of our contractors' cost to increase in real terms, as real labour increases are reflected in their cost estimates and, therefore, in the fixed price offers provided to us. Our primary main contractors have confirmed this by way of actual recent project cost estimates that demonstrate:

- For Zinfra, labour rate increases of [C-I-C]% per annum.
- For Downer, labour rates increases of [C-I-C]% per annum.
- For CPP, labour rates increases of [C-I-C]% per annum.

These examples show that labour rates exceeding CPI growth are embedded in our contractors' cost estimates which in turn are passed onto us. This includes for projects spanning multiple years, which is often the case for transmission projects, in contrast to distribution where projects are typically shorter-term. Approximately half of our capex forecast comprises major station projects that generally span 3 to 4 years. In these circumstances, our ability to adjust our use of contracted services to address changes in the labour market and/or economic climate is limited, as stated by the AER in its decision for SA Power Networks.[44]

We are able to provide evidence of the aforementioned practices by our contractors to the AER upon request.

Our proposed approach to real cost escalation for external labour is further supported by the material increase in demand for skilled workers that will be needed to deliver large scale energy

[44] AER 2020, *SA Power Networks Distribution Determination 2020 to 2025, Attachment 5 Capital expenditure, Final Decision*, p. 65.

infrastructure projects (including those set out in the ISP) during the next regulatory period. These projects compete directly with the capital program we have developed for the next regulatory period, increasing the scarcity of contract labour resources and, all else equal, driving up the price of contracted labour.

The ISP has identified several committed and planned projects for the NEM that will require a large construction workforce to deliver. There is a large pipeline of construction projects in Victoria. The construction phase of the Western Victoria transmission network project alone, with a forecast cost of $370 million, is expected to occur between 2022-23 and 2025-26. Additionally, the planned projects for Victoria with an estimated value of $7.4 billion, is expected to occur sometime between 2022-23 to 2035-36 (14 years). This equates to $555 million per year. The skillsets for these projects are very similar to the skillsets that we need for our capex program, placing upward pressure on our external labour costs.

The table below provides a summary of these projects and the associated capital expenditure.

Table 4-3: Integrated System Plan – estimated project costs ($M)

	Timeframes	2023-24
Western Victoria transmission network	Construction between 2022-23 and 2025-26.[45]	$370[46]
VNI minor	This upgrade is expected to be delivered in 2022-23.	$105
VNI West	May be required by 2027-28, but in most scenarios has optimal timing in the mid-2030s.	$4,140[47]
Marinus Link*	Optimal timing ranges from 2028-29 to 2035-36.	$3,155[48]
Total		**$7,400**

* Includes Tasmanian share of project costs

Source: *2020 ISP Interconnector Projects: Transmission Cost Estimate Summary*

Given these projects represent a very material step up from the volume of work that has occurred over past regulatory periods, it is unrealistic to assume that there will not be upwards pressure on real wages for required resources.

The Victorian and Federal Governments have also recently announced large funding for Victorian construction projects, totalling over $5.2 billion, expected over the next few years. These projects will also compete with our contractors for skilled labour, especially in the civil space. The table below sets out several recent project announcements.

45 https://www.westvictnp.com.au/project-information.

46 https://aemo.com.au/initiatives/major-programs/western-victorian-regulatory-investment-test-for-transmission/the-preferred-investment-option.

47 Kerang route $2,410 million plus Shepparton route $1,730 million.

48 Stage 1 $1,845 million plus stage 2 $1,310 million.

Table 4-4: Recent funding announcements for construction projects in Victoria

	Cost ($M)
Fast-tracked projects - announced in November 2019	$514[49]
Buildings Works package - announced in May 2020	$2,700[50]
Unlocking Victoria's infrastructure job - announced in July 2020	$525.8[51]
Transport infrastructure boost - announced October 2020	$1,510[52]
Total	**$5,250**

In light of the unprecedented scale of infrastructure development taking place prior to and during the next regulatory period, a departure from the contracted labour cost escalation approach set out in the AER's recent distribution determinations is required for this transmission reset. The AER's recent approach to apply CPI to external labour costs – which constitute 50% of the weighting in our real cost escalation approach– does not reflect the efficient contract costs we expect to incur during the next regulatory period.

In the draft decisions for the Victorian electricity distribution networks, the AER accounted for legislated increases in the superannuation guarantee in the labour price growth forecasts. This involved factoring in a decrease in labour growth before adding the legislated superannuation guarantee increases to the WPI growth forecasts. We have adopted the AER's approach in developing our real cost escalators for external labour.

Our proposed escalators are set out in the table below. The underlying data and calculations have been provided as a supporting document. As noted above, this is a placeholder forecast that will be updated to reflect ongoing impacts of COVID-19, and averaged with another forecast, prior to submitting our Revised Revenue Proposal.

Table 4-5: Proposed real cost escalators, external labour

	2022-23	2023-24	2024-25	2025-26	2026-27
Forecast Construction WPI	0.40%	0.56%	1.04%	1.25%	1.25%

Source: BIS Oxford Economics; AusNet Services analysis

Note: Includes superannuation guarantee increase adjustment; as the forecast provided by our consultant did not go beyond 2025-26, we have assumed the 2025-26 value in 2026-27

Consistent with the AER's standard approach to forecasting internal labour, as we have applied in our opex forecast, we consider that an average of two forecasts is also appropriate for external labour. Given the expected real cost increases in external labour that will be faced by transmission networks during the next regulatory period, we encourage the AER to re-introduce a construction WPI into the scope of its consultant's (DAE) labour cost escalation forecasts, such that an average of two forecasts can be applied.

[49] https://www.pm.gov.au/media/1-billion-road-boost-victorian-economy.

[50] https://www.abc.net.au/news/2020-05-18/daniel-andrews-premier-victoria-coronavirus-construction-blitz/12258066.

[51] https://www.pm.gov.au/media/more-half-billion-dollars-unlock-infrastructure-jobs-victoria.

[52] https://www.pm.gov.au/media/morrison-government-invests-11-billion-transport-infrastructure-boost-victorian-economic.

4.5 Customer engagement

We undertook an extensive program of customer engagement in preparing our capex plans. This included substantial time spent understanding customers' preferences, including as they relate to price and reliability trade-offs, and how we could align our capital expenditure proposal with these preferences. Our engagement included the following activities:

- Establishment of a **Customer Advisory Panel** to guide our engagement with customers and to provide feedback on our plans, including our capex forecast.
- **Briefing Sessions**. The primary purpose of these sessions is to share information and provide context. This included holding a dedicated session to inform stakeholders of the implications of AEMO's Final 2020 ISP for our transmission plans and prices for Victorian energy users.
- **Deep Dive workshops**. These sessions focussed heavily on capex, with topics including our economic assessment approach for major station projects; an in-depth analysis of two major station project case studies; our ground-wire asset replacement program capex; and how to smooth our overall forecast to manage deliverability risks, while also ensuring our customers' expectations of reliable supply and safety are met. Further information on the deep dive workshops is provided in Table 4-7 at the conclusion of this section.
- **In-depth interviews.** As part of our on-going customer satisfaction research, we conducted in-depth interviews with a sample of 10 customers and stakeholders, including directly connected customers, other network businesses, generators and AEMO to garner a better understanding of current performance and areas of improvement. These interviews, which we conduct annually, provided an opportunity to also seek general feedback on current and future expectations and priorities regarding our service in an environment of energy transformation, and more specific feedback about our preliminary capex forecasts.
- Presentation materials from the above sessions are located on our website **here**. The relevant customer engagement and research reports have been submitted with this Revenue Proposal as supporting documents.
- We have also considered stakeholder feedback via the concurrent electricity distribution reset process, recognising that several proposed ICT programs are shared across our three networks to unlock synergy benefits. The electricity distribution review NewReg process also provided a wealth of current research about end-user electricity consumer views and preferences. While this research focused on identifying the preferences and needs of residential and business customers connected to the distribution network, many of the key themes and insights from that research are relevant to the development of our plans for the transmission network.

The following table identifies the key messages we have heard from customers and how we are responding to these in our capital expenditure plans. Our customer engagement approach, and how we have listened to customers and reflected their views in our plans, is discussed further in Chapter 3.

Table 4-6: How our capex forecast addresses customer and stakeholder feedback

Stakeholder feedback	Our response
Affordability is a concern to all customer groups. In particular, increased costs can affect the viability of many large businesses.	Victorian transmission prices have declined steadily in real terms for 20 years. While this trend continued over the last 5 years, we recognise that as just one part of the energy supply chain we need to listen and respond to customer preferences on the total cost of electricity, not just our component. Under our plans, real transmission charges will remain around 60%

Stakeholder feedback	Our response
	lower than at privatisation more than two decades ago, excluding easement land tax. By maintaining the reliability and security of the existing transmission network, our plans also complement the ISP projects to ensure that competition in the wholesale electricity market is maximised and that the cheapest generation can be traded in Victoria. The ISP has been of particular interest to stakeholders because of its potential price impacts. While an increase in investment is required in the next period to maintain reliability and safety, this reflects the underlying condition of our ageing asset base. To ensure all our investments are in the long-term interests of customers, we undertake an assessment of efficient costs versus customer benefits, such as, the value placed by customers on reliability. This approach ensures that customers are only paying for prudent and efficient costs. Through consultation with our customers, we have also applied a top-down smoothing adjustment to our network capex to manage deliverability risks while also ensuring our customers' expectations of reliable supply are met. This adjustment has resulted in the deferral of expenditure for some major station projects. Our proposal will also result in a falling value of the Regulatory Asset Base (RAB) per customer, reducing the cost burden on future customers.
Customers are generally satisfied with current levels of **reliability** and are generally comfortable with our asset management approach, including our risk-based, economic assessment approach to asset replacement. For some large customers, **maintaining reliability is more important than affordability** due to the significant impacts supply interruptions can have on their production processes.	Our capex forecast has been developed to maintain the strong performance and high reliability that our customers expect of the network, in line with the updated Value of Customer Reliability values released by the AER in December 2019, which are broadly in line with the 2014 VCRs developed by AEMO. We will continue to look for more efficient ways to maintain reliability and improve our approach to asset management, building on our skills and experience and through listening to our customers and stakeholders.
Improved relationship management is a key priority for large customers, distributors and generators.	We have established a team of dedicated customer relationship managers to provide a direct contact point for large users, including directly connect transmission customers, and to proactively address customer concerns and issues. Improvements in our ICT program will also contribute to better relationship management. For example, we are making investments to improve our communication and information sharing capabilities with all customers, including large users.

Source: AusNet Services

As previously noted, we held two deep dive workshops on our capex proposals with attendees including customer representatives, consumer advocates, AER representatives, consumer challenge panel representatives and other stakeholders. The deep dive workshops were designed to:

- share information on our capex proposals with the aim of building stakeholder understanding and knowledge of the drivers of our capex forecast;
- consult on and enable open and frank discussion of key elements of our proposals, with a focus on issues where customer feedback may inform the positions taken in the proposal; and
- enable us to consider the feedback and views of attendees while developing our capex proposals.

One workshop covered major stations capex, while the other addressed ICT and asset replacement programs. The topics covered and the main outcomes of these workshops are summarised in the table below, as well as where further information has been provided in this Revenue Proposal to address stakeholder feedback and queries. As noted above, presentation materials from these sessions are located on our website and the deep dive summary reports have been submitted with this Revenue Proposal as supporting documents.

Table 4-7: Overview of capex deep dive workshops

Topics addressed	Key outcomes	Further information provided in this Revenue Proposal
Major station projects deep dive workshop (Deep Dive 2)		
This workshop provided: • **Overview of indicative capex forecast and proposed major station projects** • **Economic assessment framework for major station projects** • **Major station project case studies** • **Capex profile and deliverability considerations**	In response to stakeholder feedback and queries: • AusNet Services confirmed that the economic assessment framework ensures the most efficient option is progressed, most projects are staged replacements, and sensitivity analysis is conducted to manage uncertainty of key inputs. • AusNet Services undertook to provide detailed information on its economic assessment of projects (including key assumptions and inputs, and safety risk assessment approach) in the Revenue Proposal and supporting documents. • AusNet Services confirmed that it fully investigates non-network options as part of the RIT-T process and is investigating (with UED) whether demand management can be used to defer	Major station project planning reports AMS 10-24 Asset Renewal Planning Guide Section 4.14

Topics addressed	Key outcomes	Further information provided in this Revenue Proposal
	significant upgrades of the Cranbourne Terminal Station. • AusNet Services undertook to engage with AEMO to fully explore the interactions between its investment projects and the ISP. • AusNet Services undertook to further investigate expenditure smoothing approaches, having regard to feedback around price and reliability preferences and relative NPVs of various projects.	
Asset replacement and ICT program deep dive workshop (Deep Dive 3)		
This workshop provided: • **Recap of joint AusNet Services-AEMO briefing session** • **Overview of proposed total capex, including composition** • **Comparison of proposed and historic ICT capex** • **Description of benefits of ICT investment** • **Intelligent Networks case study, including evaluation of options for meeting the identified need** • **Ground wire asset replacement case study, including asset condition and risk assessment, and**	Overall, participants were generally supportive of AusNet Services' capex proposal, and they recognised that AEMO and AusNet Services had worked together to coordinate the ISP and AusNet Services' replacement plan. Stakeholders provided helpful feedback, and whilst a number of questions were raised, the deep dive session did not raise any issues that required us to materially revise our capex proposals. In response to stakeholder feedback and queries: • AusNet Services undertook to provide information on ICT opex and capex in its Revenue Proposal, to demonstrate that the mix of capital and recurrent expenditure minimises total life present value cycle costs • AusNet Services confirmed that its data management systems will enable the capture of information that the business expects to leverage across the network to deliver further value to customers. These benefits will be identified in the development of the Intelligent Networks program brief.	Section 4.6 Section 5.10 ICT Program Brief - Intelligent Network Operations AMS 10-79 - Transmission Line Conductors AMS 10-24 Asset Renewal Planning Guide

Topics addressed	Key outcomes	Further information provided in this Revenue Proposal
repex benchmarking	• AusNet Services undertook to provide further explanatory information in its Revenue Proposal on asset condition and risk assessment methodologies, and the evaluation and sensitivity testing of benefits of the ground wire replacement program.	

Source: AusNet Services

4.6 Forecasting methodology

Replacing assets based on condition, rather than age, requires us to monetise the risk of an asset failing due to its condition and compare this to the cost of replacing the assets. By doing so, we ensure that all decisions to replace assets are prudent and efficient.

Our capex forecasts have been prepared in accordance with our expenditure forecasting methodology document, which was submitted to the AER on 27 March 2020. As noted in that document, our objective is to ensure that our capex forecast is accurate and unbiased, complies with the NER and promotes the National Energy Objective (NEO).

Accordingly, our methodology is focused on identifying an overall program of capital work that will prudently and efficiently maintain the safety, quality, reliability and security of supply of prescribed network services at minimum efficient cost. This approach is consistent with the NEO and the capex objectives and criteria in the NER.

In broad terms, we rely on the following robust planning and governance processes to drive capex forecasts that comply with the NER requirements:

- Asset management practices, which deliver an optimal balance between quality, safety, reliability and security of electricity supply with price and efficient investment for the long term interests of consumers.
- Asset replacement planning, based on a risk-based economic evaluation, is used to ensure the efficient timing of network investment.
- Investment decision-making practices are supported by a robust project governance framework, which incorporates continuous improvement to ensure projects are delivered at lowest efficient cost.
- AusNet Services' network capex forecast includes only asset replacement expenditure. This is in accordance with the division of TNSP responsibilities in Victoria. AEMO plans and directs augmentation of the shared transmission network, and the distribution businesses have this role for the connection assets where they take supply. In planning asset replacement projects and programs, we conduct joint planning with AEMO in relation to future Victorian shared transmission network augmentations. With the increasing need for augmentation of the transmission network to accommodate the transition toward a renewable-led energy future, the transmission development pathway indicated by AEMO's Integrated System Plan is an increasingly important consideration.
- Our proposed major station projects illustrate how we work with AEMO to take account of interactions between our projects and ISP projects. As a consequence, the timing, design and scope of our major station projects have been optimised to deliver the lowest long-term

total costs to customers. This includes the deferral of a $33 million project to replace the F2 transformer at South Morang Terminal Station by more than five years due to reduced consequences of failure as a result of the VNI-Minor upgrade. In addition, an investigation is underway to optimise the Sydenham Terminal Station major project, given its interaction with the Western Victorian Transmission Project. While the project has been timed to coordinate with the WVTP, any scope impacts or efficiencies identified will be incorporated into our Revised Revenue Proposal.

The table below summarises how the interactions between our major station projects and the ISP upgrade projects have been considered.

Table 4-8: Interactions between major station replacement projects and ISP upgrade projects

ISP upgrade project	Geographically-related AusNet Services replacement project	Proposed expenditure in TRR ($M)	Impact of ISP on proposed replacement project
Energy Connect	RCTS Transformer Replacement Project	$23M	No Impact. Transformer provides connection service for local distribution
Western Vic	SYTS 500 kV gas insulated switchgear replacement – Integrated project	$66M	Options being reviewed to combine project activities to minimise overall costs and reduce system outages.
VNI-Minor	SMTS F2 Transformer replacement	$0M ($33M Deferred)	SMTS F2 transformer delayed by more than five years due to decreased consequences of failure. Therefore $33M of expenditure has been deferred out of the TRR forecast period
	SMTS 500 kV gas insulated switchgear replacement – Stage 1	$18M	500 kV switchyard not impacted
VNI-West	SHTS Transformer & switchgear replacements	$18M	No Impact. Transformer provides connection service for local distribution
Marinus	No geographically related asset replacement project during 2022 to 2027 revenue period	N/A	N/A

Source: AusNet Services

Whilst the ISP presents a 20-year outlook plan, near term priorities can change in this rapidly transforming sector, and there is potential for such changes to adjust our own capex plans for alignment. We also consult with the Victorian distributors in relation to future connection asset augmentations. Close engagement with these parties ensures that asset replacement and capacity augmentation works are optimised, and all opportunities for cost synergies are identified.

Our forecasting approach

Our forecasting approach for replacement capex is based on economic justification and comprises a robust assessment framework to determine the preferred option and its economic timing. The approach has two stages, project- and program-based evaluations (bottom-up) and, aggregation and efficiencies (top-down). We describe each of these below. We also briefly discuss our approach for non-network expenditure.

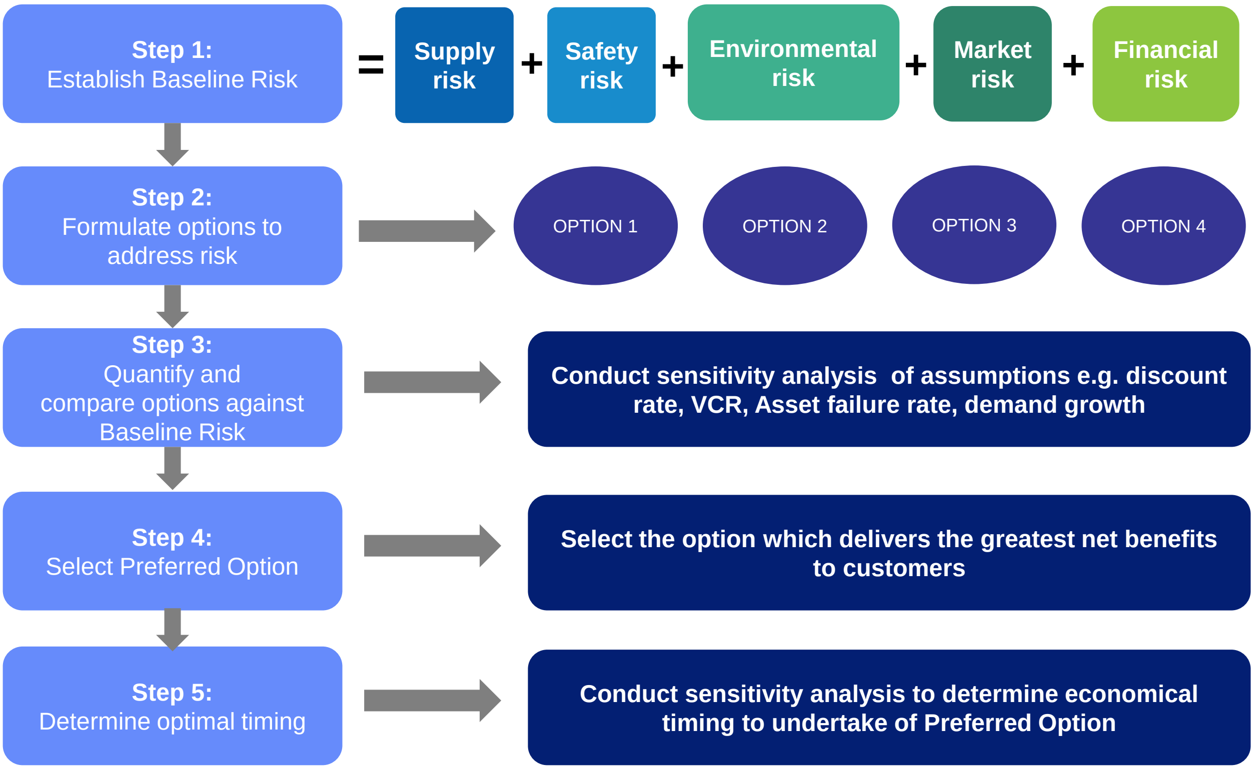
Project- and program-based evaluation

We seek to deliver optimal electricity transmission network performance by ensuring that all decisions to replace or maintain network assets are economically justified and appropriately consider all relevant criteria. The relevant criteria include:

- Safety;
- Demand for network services;
- Performance and condition of network assets;
- Reliability and security of supply;
- Technological advancements;
- Wholesale market impacts;
- Changing nature of generation and demand; and
- Impacts on climate change on network assets.

The figure below depicts the economic assessment framework we use to determine a project-based replacement decision. Further information is available in our expenditure forecasting methodology and individual Planning Reports for our proposed major station projects.

Figure 4–5: Economic assessment framework

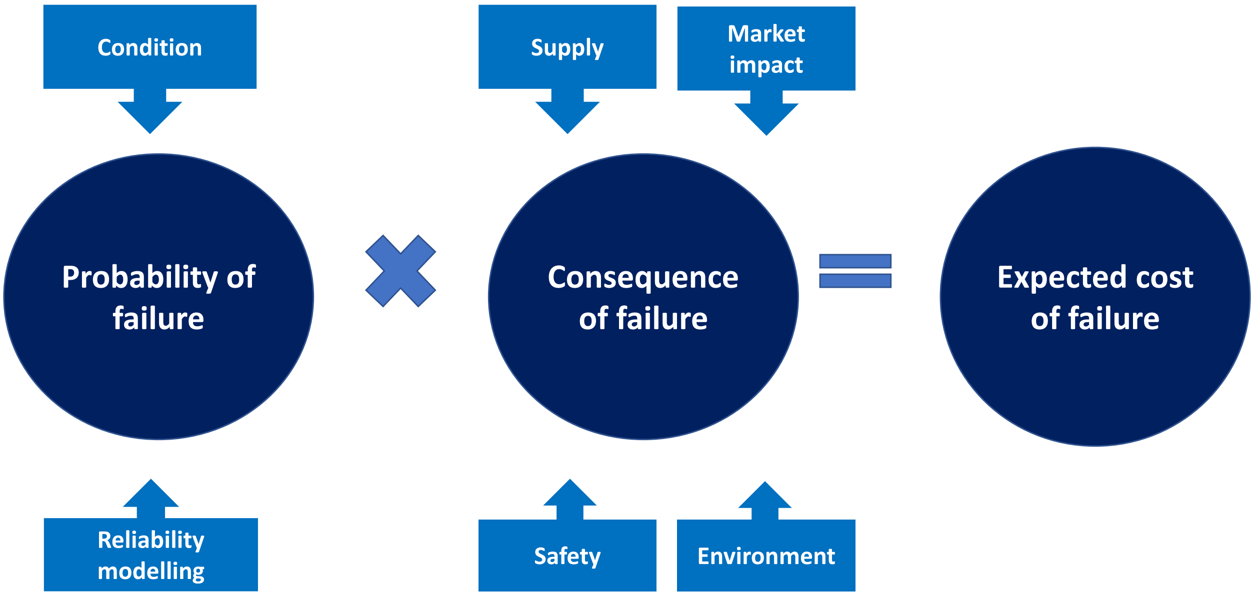


Source: AusNet Services

Step 1 – Establish Baseline Risk

The first step in the process is to evaluate the need for an asset replacement. This assessment is based on asset class modelling that identifies those assets on our network that present the highest risk, based on asset condition and consequences of failure. This is an economic evaluation, the result of which is an **expected cost of failure** for individual assets**,** as demonstrated by the figure below. This establishes the baseline risk, which is the risks that our network and customers would be exposed to under a "business as usual" (or "do nothing") approach.

Figure 4–6: Expected cost of asset failure



Source: AusNet Services

Establishing the Baseline Risk allows the comparison of the benefits of alternative options when implementing network or non-network solutions. The components that make up the Baseline Risk are shown in the figure below. The magnitude of each type of risk, and therefore the benefits of implementing a solution, varies from project to project depending on the nature and location of the assets

Figure 4–7: Baseline risk components

Risk component	Definition
Supply Risk	The risk of supply being lost to customers due to an asset failure
Safety Risk	The risk of explosion and fire due to asset failures (e.g. design issues), causing injury/fatality to employees or the public.
Environmental Risk	The risk arising from oil spills from plant (e.g. power transformers), resulting in costs due to clean-up and environmental impact costs.
Market risk	The risk lower cost generators cannot supply the NEM, resulting in higher wholesale prices
Financial Risk	The failure rate-weighted cost of undertaking reactive maintenance or replacing failed assets given the ongoing need for energy

Source: AusNet Services

As shown above, the Safety Risk of an asset failure makes up one element of the Baseline Risk. This is calculated by determining the safety risk cost discounted by the likelihood of the following consequences:

- Probability x Cost of Lost Time Accident
- Probability x Cost of Death/Serious Injury to the Public
- Probability x Cost of Death/Serious Injury to Staff.

Since the last reset, we have worked with other Victorian network businesses and Energy Safe Victoria to significantly refine these assumptions. This has improved the robustness and consistency of our overall economic assessment approach and ensured it reflects best industry practice.

Step 2 – Formulate Options to Address Baseline Risk

The next step is to examine the technically feasible options to address the identified risk. The options that we typically consider for individual projects are shown below. This includes detailed consideration of whether asset replacements can be deferred or staged over multiple regulatory periods. We also seek proposals from proponents of non-network solutions (either stand-alone or in conjunction with network solutions) as part of the RIT-T process.

Figure 4–8: Asset replacement options

Baseline / Business as Usual	Used as a reference to quantify the relative benefits of options that address the baseline risk.
Deferred replacement	Defer replacement through asset refurbishment or operational measures. Develop contingency plans for asset failure events e.g. temporary load transfers, holding spares which can be used across a number of stations.
Integrated replacement	Conduct like-for-like replacement of all assets with poor condition score in a single project. In cases where a number of assets require replacement, major station rebuild takes advantage of project synergies not available for single asset replacement.
Staged replacement	Replace highest risk/poorest condition assets, followed by replacement of other deteriorated assets in subsequent years (e.g. 5-10 years later) as separate projects.
Non network alternatives	Use embedded generation and/or demand side response alternatives in combination with network options (hybrid options).

Source: AusNet Services

Steps 3 and 4 – Quantify and Compare Options against Baseline Risk and Identify Preferred Option

After identifying all technically feasible options, we quantify their costs and benefits. The costs are determined by:

- Developing a technical scope of works
- Applying our standard cost estimating process that utilises standard unit rates (based on recent projects and contracted procurement costs).

The benefits (avoided costs/risks) of proceeding with an option are probability weighted and may include:

- **Supply**: the value of energy not supplied to customers
- **Safety:** risk cost of injury or death due to explosion
- **Market:** risk of increased generation costs
- **Environmental**: risk cost of oil spills requiring clean-up
- **Financial**: risk costs associated with emergency asset works
- **Avoided costs:** reduced maintenance expenditure from replacing existing assets.

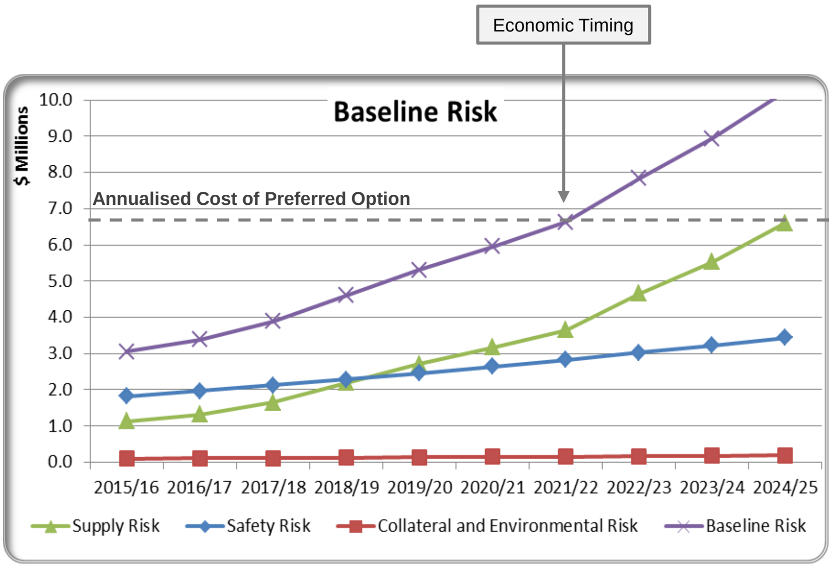
We conduct net present value (NPV) analysis to compare options on an equal basis. The option that delivers the maximum net benefit to customers over the analysis period (typically 45 years), in NPV terms, is the preferred option.

Step 5 – Determine Economic Timing

Once the preferred option has been selected a detailed project scope and detailed project cost can be estimated. We employ a detailed technical scope of works (refined from the preferred option) and current unit costs for installing the assets. This resulting cost estimate is the most likely cost of the project and assumes the scope of work will not change during the detailed design and construction phases. The cost estimate does not capture likely changes in unit costs, but accounts for the expected cost of various project contingencies (estimated using Monte Carlo analysis).

The economic timing of the preferred option is established by comparing the annualised total cost of the selected option with the annual incremental benefits. Under this approach, the economic timing is identified as the point in time at which the annual incremental benefits just exceed the annualised cost. The figure below provides an illustrative example of this assessment.

Figure 4–9: Illustrative example of economic timing assessment



Source: AusNet Services

Sensitivity studies around the discount rate, asset failure rate and demand scenarios are conducted as part of the economic evaluation, including the identification of the optimal timing. This step ensures that the proposed replacement capex is prudent and efficient, having regard to a range of reasonable scenarios.

The results of the economic assessment approach described above, including sensitivity analysis, is set out in the individual project Planning Reports provided with this Revenue Proposal.

As with major station projects, asset replacement programs are economic when the consequence of failure exceeds the cost of replacement. However, unlike major station projects, which target the replacement of deteriorated assets at a single location, replacement programs involve the replacement of individual types of asset across the entire network. To determine the economic volume of a particular type of asset to replace, we undertake an economic assessment of the costs and benefits (avoided risks), which is conceptually similar to the process described above for projects.

For individual asset replacement programs, the economic replacement volume and locations are set out in the Plant Strategies provided with this Revenue Proposal.

Aggregation and efficiencies

While project-based evaluations underpin our repex forecasts, various other factors are factored into our total repex forecast as applicable. For example:

- Timing of minor replacement works may be adjusted so they can be included in a major replacement project to attain synergies in project design, project management and project establishment costs;
- Timing of project based replacements may also be adjusted so they can be combined with AEMO's shared network augmentation requirements (as discussed above in relation to ISP projects) or the distributors' connection augmentation needs; and
- Project timing is also reviewed so that projects with the highest asset failure risk or greatest impact on customers from failure are addressed more quickly, while lower risk projects may be deferred.

In addition, the aggregation process requires us to undertake additional steps to ensure that the forecasts satisfy the NER requirements, including:

- Identifying contingent projects, if applicable, which are specifically designated projects with optimal timing subject to the occurrence of relevant trigger events;
- Applying consistent cost escalation assumptions for labour and material costs (discussed in Chapter 5); and
- Reviewing the deliverability of the total repex forecasts (discussed in section 4.12).

Top-down review

As discussed in the sections above, our capex forecast is developed using a bottom-up approach. A series of projects and programs are proposed to address various drivers.

Each program identifies a driver for expenditure and estimates the volume and cost of assets required. The identification of assets for some programs is based on asset or fleet specific information and may not take into account interrelationships with other works. There is therefore the potential for overlap, and synergies, between programs where two or more bodies of work are undertaken at the same location or propose to replace the same asset. In some cases, the replacement of one asset class may require the replacement of other physically or electrically connected assets. In other cases, it is cost efficient to bring forward non-essential replacements to coincide with required work.

AusNet Services has therefore conducted a top-down review to ensure that any interrelationship between components of the program are accounted for in the capex forecast. Whilst AusNet Services seeks to address the interrelationship between components of the program in the bottom up build, we have analysed the potential overlap and synergy between programs and projects. This has resulted in adjustments to our proposed circuit breaker and disconnector and earth switches asset replacement programs, to remove assets being replaced as part of major station replacement projects at Thomastown and Keilor Terminal Stations. Further information on the top-down review has been provided as a supporting document

Non-network expenditure

In addition to replacement capital expenditure, AusNet Services must also forecast its non-system capital expenditure requirements. Non-network capex is made up of:

- Information technology (IT);
- Buildings and property;
- Vehicles; and

- Other (principally tools and equipment).

Except for corporate IT systems, capital expenditure on non-network assets is generally recurrent in nature, which reflects the economic life cycles of each asset type. IT capital expenditure is forecast based on AusNet Services' corporate IT strategy, which itself has been set in a manner consistent with the obligations of, and expectations placed upon, a prudent network service provider.

The AER has recently introduced a new framework for assessing the efficiency of proposed ICT investments. While this framework currently applies only to electricity distribution networks, we have developed our proposed ICT capex program in a manner that is consistent with this assessment framework.

As a result of an accounting standards change that came into effect in 2019-20, our proposed capex forecast also includes a small amount of capitalised lease costs.[53] An offsetting reduction to our lease operating costs is reflected in our 2019-20 reported opex, ensuring that lease costs are not also captured in our opex forecast. Capitalised leases are discussed further in Chapter 8.

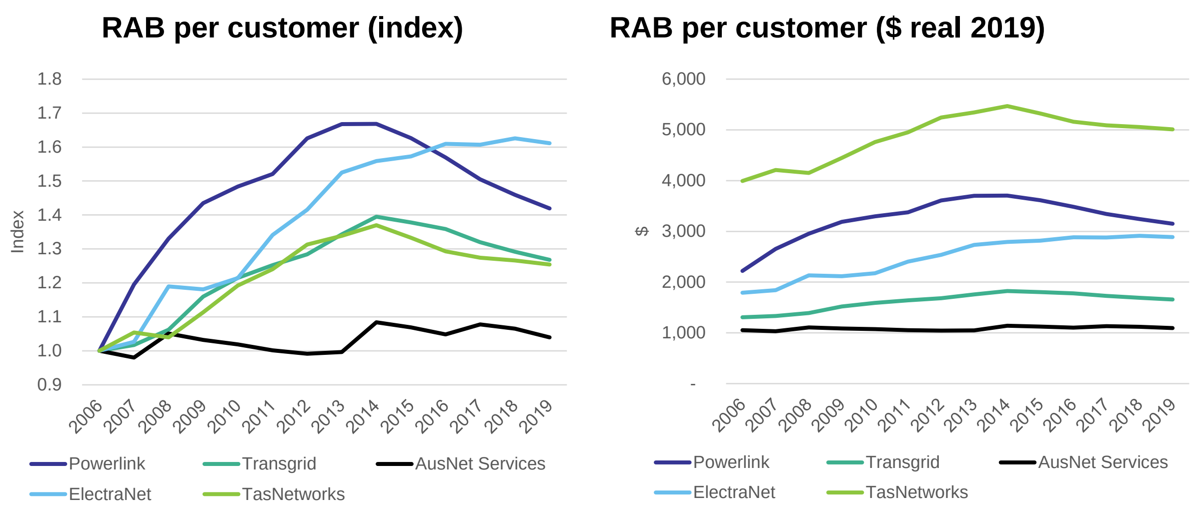
Our proposed non-network expenditure is discussed further in sections 4.12 and 4.13.

4.7 Capex benchmarking

AusNet Services has regard to a range of network performance measures against which to evaluate the reasonableness of its capex proposal. This evaluation provides a further cross-check, even though the forecast capex has been developed using a methodology that is focused on economic efficiency and prudency.

A key parameter that confirms that our capex compares favourably with our peers is the value of the RAB per end-use customer. As shown in the figure below, our RAB per customer has remained substantially lower than any other transmission network in Australia, reflecting our application of prudent investment criteria and rigorous cost benefit analysis over the last two decades. This has allowed us to avoid increasing the cost burden on Victorian customers over time, in stark contrast to other jurisdictions. Our forecasts indicate that our RAB per customer is expected to decline over the forthcoming period.

Figure 4–10: RAB per end-use customer



53 Forecast capitalised lease costs of $1.6M are not included in the figures and charts presented in this chapter.

Source: AER, *Electricity network performance report 2020*, September 2020; AusNet Services analysis

4.8 Variations in forecast capex from historic capex

NER S6A.1.1(7) requires a Revenue Proposal to provide an explanation of any significant variations in the forecast capex from historic capex.

Our forecast capex for the forthcoming regulatory period is, on average, 9% higher per annum than actual and expected capex in the current regulatory period. The main driver of this increase is the forecast increase in Major Station Project expenditure, to address risks associated with deteriorating station assets.

The table on the following shows the trend in capex by category since 2014-15.

Table 4-9: Actual and Forecast Capex for the Previous, Current and Next Regulatory Periods ($M, real 2021-22)

	2014-15	2015-16	2016-17	Av 2014-17	2017-18	2018-19	2019-20	2020-21	2021-22	Av 2017-22	2022-23	2023-24	2024-25	2025-26	2026-27	Av 2023-27
Major Station Projects	97.4	74.3	76.3	*82.7*	86.1	94.1	71.6	59.7	46.7	*71.6*	101.7	105.1	102.3	72.7	42.4	*84.8*
Replacement Programs	43.0	41.8	36.5	*40.4*	36.9	37.4	60.0	61.7	50.1	*49.2*	45.0	44.1	42.6	37.2	44.6	*42.7*
Safety, Security and Compliance	8.2	27.0	18.5	*17.9*	6.8	5.8	7.9	2.9	13.3	*7.4*	8.9	8.2	10.4	16.1	10.7	*10.8*
ICT	22.0	9.3	7.1	*12.8*	10.2	12.9	12.5	20.0	17.9	*14.7*	18.0	18.4	19.4	15.0	13.0	*16.8*
Non Network	4.5	4.6	6.4	*5.2*	2.7	2.1	5.6	2.6	4.5	*3.5*	3.7	4.3	4.9	3.8	3.9	*4.1*
Total	**175.1**	**157.0**	**144.7**	***158.9***	**142.7**	**152.3**	**157.7**	**147.0**	**132.6**	***146.4***	**177.4**	**180.0**	**179.5**	**144.7**	**114.5**	***159.2***
Related Party Margin	0.9	0	0	*0.3*	0	0	0	0	0	*0.0*	0	0	0	0	0	*0.0*

Note – no related party margins for the purposes of NER S6A.1.1(6)(ii) have been incurred since 2014-15 or are included in the capex forecast. In this Table ABS September quarter CPI has been applied for escalation into real $2021-22 in all years. Amounts shown for 2014-15 to 2019-20 are actuals, all other amounts are forecast.

An explanation of the main variances over time at a category level is provided below.

Major station projects

In the previous and current regulatory periods, major stations asset replacement work has been focused on critical, aged CBD stations. This significant investment program is now nearing completion. A small component of the forecast capex for the next regulatory period relates to CBD station rebuilds, to complete the West Melbourne Terminal Station redevelopment.

The focus for the next regulatory period and beyond will shift to aged network backbone switching stations and aged rural connection stations with increasing criticality.

Our forecast Major Stations Replacement capex for the next regulatory period is 18% higher than the expected actual expenditure for the current period.

As explained in section 4.9, this expenditure increase reflects:

- forecast deterioration in asset condition at a number of stations over the next period, resulting in the need to increase expenditure to efficiently address safety and reliability risks through condition-based replacement; and
- a shift in the station repex away from 220 kV system assets to replacement of more complex and expensive 500 kV assets.

Asset replacement programs

Over the previous and current regulatory periods, station assets from the 1960s have largely been replaced. Now, assets that were installed in the 1970s and 80s are displaying signs of deterioration, are approaching the end of their technical lives and, based on their condition, need to be replaced.

Despite the ageing nature of our asset base, our forecast expenditure on asset replacement programs for the next regulatory period is 13% lower than the expenditure we expect to incur in the current period. This forecast reflects our risk-based approach to economic assessment of asset replacement expenditure. As discussed in section 4.6, asset replacement programs are assessed as being economic only when the expected cost of asset failure exceeds the cost of replacement.

Further information on our asset replacement programs expenditure is provided in section 4.10.

Safety, Security and Compliance

Our capex forecast in this category is 47% higher than the amount of expenditure we expect to incur in the current regulatory period. The increase in forecast expenditure reflects:

- the need to replace deteriorated assets that, based on the likelihood and consequence of failure, are economic to replace. This includes a $29 million program to replace a number of our insulator assets based on their condition and criticality, which is a key driver of the proposed increase on current period expected spend for this category; and
- the costs of implementing several safety-driven initiatives which are required to ensure we meet our safety obligations as under the Occupational Health and Safety Regulations 2007.

Section 4.11 provides further information on our Safety, Security and Compliance expenditure.

Information and Communication Technology

Our forecast ICT expenditure for the next regulatory period is 14% higher than the expenditure we expect to incur in the current period.

Section 4.12 explains that:

- the forecast expenditure in this category compared with previous regulatory periods is in line with long term historical levels;
- new cyber security requirements and an increasingly complex operating environment are driving the overall increase in forecast expenditure requirements; and
- ICT expenditure is cyclical in nature, reflecting the timing of major upgrades (e.g. SAP) and the lifecycle replacement of ICT systems.

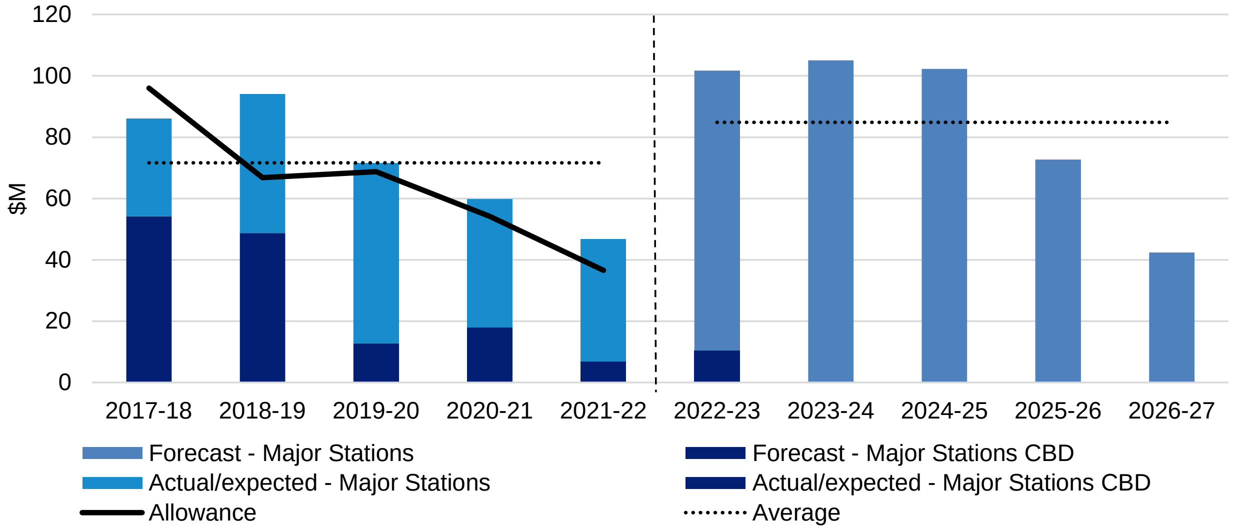
Non-network capital expenditure

Our forecast for non-network capex over the next regulatory period averages approximately $4 million per annum. This represents a 17% increase compared to the expenditure we expect to incur in the current regulatory period, reflecting modest increases in motor vehicles purchases and buildings capex.

4.9 Major stations capital expenditure

We are proposing major stations capex of $424.2 million for major station projects in the forthcoming regulatory period. Our major stations proposal represents 53% of the total capex forecast and is 18% ($66 million) higher than the amount of expenditure we expect to incur in the current regulatory period. This is illustrated in the figure below.

Figure 4–11: Actual, expected and proposed major stations capex ($M, real 2021-22)



Source: AusNet Services

The major stations forecast includes several existing projects and 15 new projects at terminal stations where, based on asset condition, it is economic to replace assets in the next regulatory period. Compared to the current period, more of the new projects involve replacing 500 kV equipment (one in the current period compared to five in the next period), which is more expensive to replace compared to 220 kV equipment. Our repex program has focused much more heavily on the older 220 kV system in the last 15 years.

As discussed in section 4.6, the projects described in this section have been forecast using a risk-based, economic assessment framework that compares the costs of delivering each project with the long-term customer benefits that will be provided.

Committed projects at the West Melbourne and Springvale Terminal Stations and at Hazelwood Power Station account for $30 million (7%) of our proposed major stations capex. These projects are on track for completion by the first year of the next regulatory period.

RIT-Ts are underway for our proposed projects at the East Rowville, Templestowe and Horsham terminal stations, which account for $98 million (23%) of the proposed major stations spend. RIT-Ts are scheduled to commence shortly for the projects proposed for the Shepparton, Brooklyn and Thomastown terminal stations. Further information on the RIT-Ts that are currently underway, including published documentation, is available on our website here.

The table below sets out the RIT-T status for each proposed major station project where the RIT-T must be satisfied, including indicative timelines for projects where we are yet to commence RIT-Ts.

Table 4-10: Major station projects - RIT-T status and indicative timelines

#	Station	Description	Initiate	Stage 1 PSCR	Stage 2 PADR	Stage 3 PACR
1	**ERTS**	Redevelopment Stage 2				Q4 2020
2	**TSTS**	66kV Transformer and Circuit Breaker Replacement				Q4 2020
3	**HOTS**	SVC Replacement			Q2 2021	Q4 2021
4	**SHTS**	Transformer B2 and B3 Replacement		Q1/Q2 2021	Q3/Q4 2021	Q4 2021
5	**BLTS**	66/22kV Circuit Breaker Replacement		Q1/Q2 2021	Q3/Q4 2021	Q4 2021
6	**TTS**	66kV Circuit Breaker Replacement		Q1/Q2 2021	Q3/Q4 2021	Q4 2021
7	**KTS**	500/220kV Transformer Replacement		TBC	TBC	TBC
8	**MLTS**	Circuit Breaker Replacement		TBC	TBC	TBC
9	**RCTS**	Transformer and Switchgear Replacement		TBC	TBC	TBC
10	**SMTS**	330/220kV Transformer Replacement Stage 2		TBC	TBC	TBC
11	**SMTS**	500kV GIS Replacement		TBC	TBC	TBC
12	**SYTS**	500kV GIS Replacement		Q1/Q2 2021	Q3/Q4 2021	Q4 2021
13	**GNTS**	66kV Circuit Breaker Replacement		TBC	TBC	TBC
14	**HOTS**	66kV Circuit Breaker Replacement		TBC	TBC	TBC
15	**FTS**	66kV Circuit Breaker Replacement		TBC	TBC	TBC

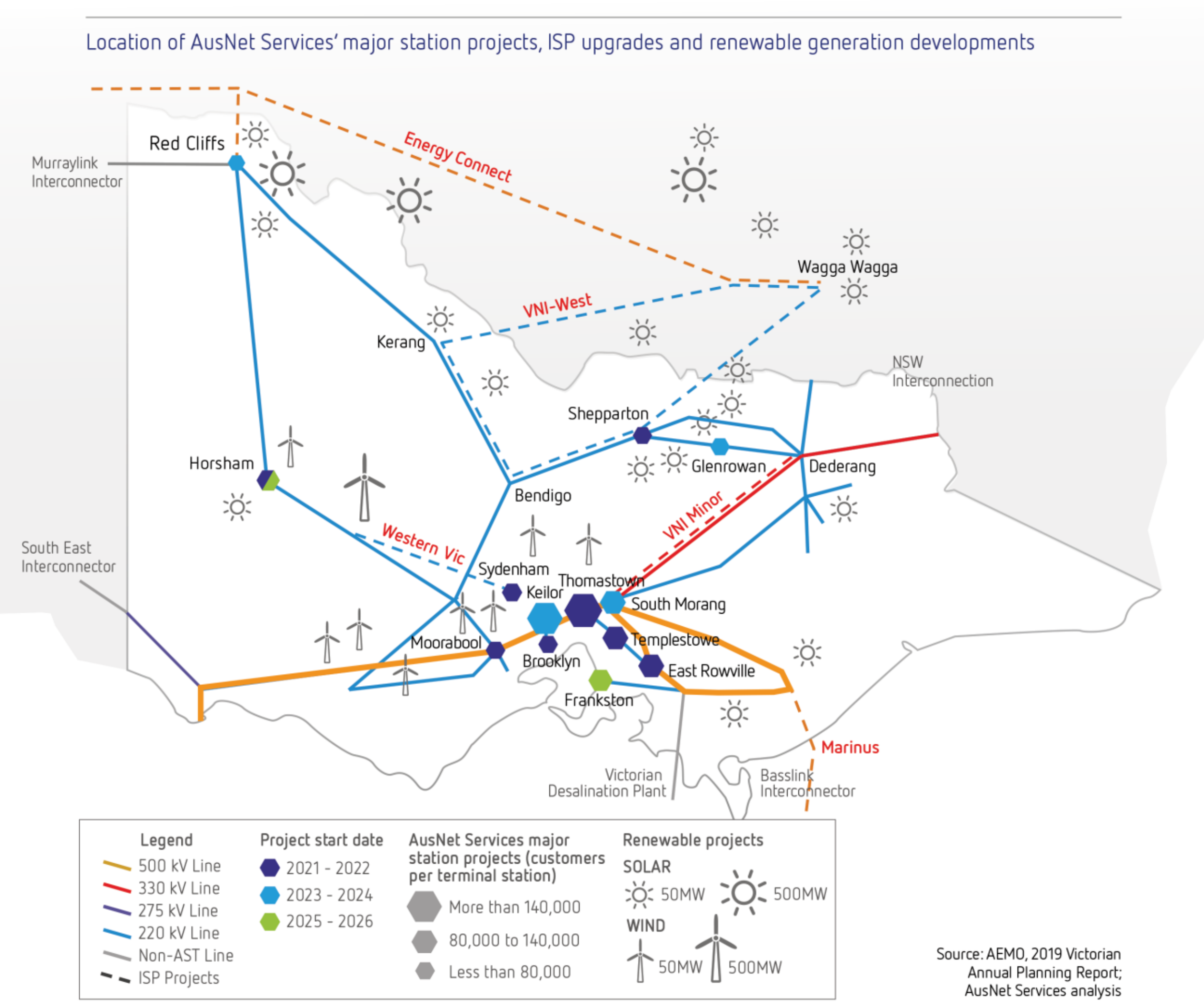
Source: AusNet Services

Note: Green = complete; Orange = underway or scheduled to commence shortly

In the previous regulatory periods, the bulk of major stations asset replacement work has been on critical, aged stations supplying central Melbourne. The focus for the next regulatory period and beyond has shifted to aged network backbone switching stations and aged rural connection stations with increasing criticality. These represent 54% and 46%, respectively, of the major station's capex forecast.

The following figure illustrates that our proposed major station projects are spread across the network, which aligns with the transition to a highly distributed sourcing of generation.

Figure 4–12: Location of major station projects in the next regulatory period



Source: AusNet Services; AEMO, *2019 Victorian Annual Planning Report*, June 2019

As noted above, a small component of the proposal remains for CBD station rebuilds, to close out the West Melbourne Terminal Station redevelopment. The works at this station will be largely completed in the current regulatory period, as planned, however coordination with connected parties means that retirement of the old 22 kV switchyard cannot occur until (likely) 2023.

The major stations redevelopment proposals are outlined in the following sections. More detailed information on each terminal station project is provided in the Planning Reports and other supporting documents that form part of this proposal.

Switching terminal stations

Switching terminal stations form the backbone of the Victorian transmission network. These stations are important nodes in the national, interconnected transmission system and the reliability of assets is critical to reliability and security of the power system. As noted above, our proposed redevelopment of these stations typically involves the replacement of 500 kV and 330 kV equipment, which is relatively expensive compared to 220 kV equipment at load serving terminal stations which have been the subject of the majority of asset replacement works previously.

Our proposed new (i.e. excluding committed projects) major switching terminal projects for the next regulatory period are summarised in the table below.

Table 4-11: Key major station replacements – switching stations ($M, real 2020, direct costs)

Major station	Description	Proposed capex (2023-27)
South Morang Terminal Station (SMTS) 330/220 kV Transformer Replacement - Stage 2	South Morang is one of the most important terminal stations on the Victorian system, with its transformers providing a crucial interlinkage between the 500 kV backbone, the NSW interconnector and the 220kV system supplying Melbourne. The SMTS H (330/220 kV) transformers provide the link between the NSW interconnector and the 220 kV metropolitan transmission network. Both H1 and H2 transformer banks (3 single phase units forming a bank) are in poor condition and have provided over 50 years of service. Stage 1 of this project installed a new H3 transformer and retained the H2 transformer as a hot spare. This project replaces the H1 transformer and associated switchgear, purchases a spare H phase and retires the old H1 and H2 transformers.	**$38.3**
South Morang Terminal Station (SMTS) 500 kV GIS Replacement – Stage 1	The SMTS 500 kV GIS is an important part of the 500 kV Victorian transmission backbone providing 500 kV connections to the Loy Yang power stations and Basslink via Hazelwood Terminal Station, and to Rowville, Keilor and Sydenham Terminal Stations around Melbourne. The GIS is in poor condition and needs renewal to maintain a reliable shared network. This project will replace a part of the SMTS 500 kV GIS assets.	**$15.7**
Moorabool Terminal Station (MLTS) CB Replacement	MLTS is an important part of the main 500 kV transmission network in Victoria. It includes 500/220 kV transformation to connect major loads and renewable generation in the western part of Victoria. As most of the primary assets were installed in the early 1980s, they are approaching the end of their technical and economic lives. This project plans to replace eight 500 kV circuit breakers and nine 220 kV circuit breakers that are in poor condition to mitigate switching constraints and safety, supply, environmental and collateral damage risks in the event of an asset failure.	**$16.4**
Sydenham Terminal Station (SYTS) 500 kV Gas Insulated Switchgear (GIS) Replacement	SYTS is a 500 kV switching station connecting SMTS KTS and MLTS and is also an important part of the Victorian main 500 kV transmission backbone and the key link to new generation capacity from the north west. SYTS has 500 kV connections to Keilor (KTS) and South Morang (SMTS) terminal stations. AEMO's Western Vic RIT-T plans to connect the new Ballarat 500/220 kV terminal station to the network via SYTS. The 500 kV GIS at SYTS has deteriorated and this plan includes replacement of these assets to ensure continued reliability of the shared transmission network. While the timing of this project is coordinated with the Western Victoria Transmission Project, an investigation is underway to optimise the total costs of both projects. Any scope impacts or	**$57.1**

Major station	Description	Proposed capex (2023-27)
	efficiencies identified will be incorporated into our Revised Revenue Proposal.	
Keilor Terminal Station (KTS) A4 500/220kV Transformer Replacement	KTS provides 500/220 kV as well as 220/66 kV transformation and supplies more than 189,000 Jemena and Powercor customers in western Melbourne. The 500/220 kV transformation is provided through 9 single phase 500/220 kV transformers that make up 3 banks of 750 MVA each and one spare phase that are in poor condition. All these transformers have provided close to 50 years of service and are in poor condition. This project will replace one 500/220 kV transformer (a bank of three single phase transformers) to maintain supply reliability.	**$62.5**
Total		**$189.9**

Source: AusNet Services

Connection terminal stations

These are the terminal stations from which load customers take supply. Predominantly the customers are the distribution networks. Transformers at the terminal stations step the operating voltage down from transmission voltages to distribution voltages, and a large number of distribution feeder exit points are provided. Traditionally a small number of these stations have also connected generation. This use of terminal stations is now rapidly expanding to become the norm as renewable generation is being established across the state. The capability and operability of the network must adapt to the changing role being imposed on it.

Our proposed new (i.e. excluding committed projects) major connection terminal station projects for the next regulatory period are summarised in the table below.

Table 4-12: Key major station replacements – connection stations ($M, real 2020, direct costs)

Major station	Description	Proposed capex (2023-27)
Horsham Terminal Station (HOTS) Static Var Compensator (SVC) Replacement	Originally designed as a load station, HOTS is becoming increasingly important to the successful integration of generation in Western Victoria. The SVC at HOTS was commissioned in 1986 to provide dynamic reactive power support and voltage control in North-west Victoria. The condition of the asset has deteriorated to a level where there is a material risk of asset failure, which would impact voltage control services. This project involves the replacement of the SVC.	**$28.5**
Red Cliffs Terminal Station (RCTS) Transformer and Switchgear Replacement	RCTS consists of two 70 MVA and one 140 MVA 220/66/22 kV transformers providing 66 kV supply and two 35 MVA 220/22 kV transformers providing 22 kV supply. RCTS provides supply to more than 22,000 Powercor customers via the 66 kV network and more than 6,300 customers via the 22 kV network.	**$20.1**

Major station	Description	Proposed capex (2023-27)
	This project will replace two 220/22 kV transformers, three 22 kV circuit breakers and several instrument transformers that are in poor condition.	
East Rowville Terminal Station (ERTS) Redevelopment - Stage 2	ERTS was commissioned in the 1960s and serves as the main transmission connection point for distribution of electricity to approximately 128,000 AusNet Services and United Energy customers. The condition of two (of the four) 150 MVA 220/66 kV transformers and several circuit breakers has deteriorated and need to be replaced. This project will replace two 150 MVA 220/66 kV transformers and twelve 66 kV circuit breakers.	**$20.8**
Templestowe Terminal Station (TSTS) Transformer and 66kV CB Replacement	TSTS was commissioned in 1966 and is the main transmission connection point for the distribution of electricity to approximately 116,000 (United Energy, CitiPower, AusNet Services and Jemena) customers via three 150 MVA 220/66 kV transformers. The condition of two transformers, thirteen 66 kV circuit breakers and several 220 kV and 66 kV instrument transformers has deteriorated and need to be replaced. This project will replace these assets due to the material risk of asset failure.	**$36.7**
Brooklyn Terminal Station (BLTS) 66 kV and 22 kV CB Replacement	BLTS is located approximately 10 km west from Melbourne's CBD. It was commissioned in the early 1960s and serves as the main transmission connection point for the distribution of electricity to over 64,000 (Powercor and Jemena) customers via 220/66 kV and 220/22 kV transformers. While these transformers are in good condition, most of the 66 kV circuit breakers and one 22 kV bus tie circuit breaker have deteriorated to a level where there is a material risk of asset failure. This project will replace fifteen 66 kV circuit breakers and one 22 kV circuit breaker to maintain supply reliability.	**$12.6**
Shepparton Terminal Station (SHTS) B2 and B3 Transformer Replacement	SHTS is in northern Victoria, was commissioned in the late 1960s and serves as the main transmission connection point for distribution of electricity to over 70,000 customers via three 150 MVA 220/66 kV transformers. The condition of two transformers and most of the 66 kV circuit breakers has deteriorated and there is a material risk of asset failure. This project will replace both transformers and twelve 66 kV circuit breakers to maintain supply to customers.	**$15.4**
Thomastown Terminal Station (TTS) 66 kV CB Replacement	TTS, located in the north of greater Melbourne, was established in the 1960s and provides supply to over 185,000 Jemena and AusNet Services customers via five 150 MVA 220/66 kV transformers.	**$12.4**

Major station	Description	Proposed capex (2023-27)
	This project will replace one 220 kV circuit breaker, fourteen 66 kV circuit breakers and several 220 kV and 66 kV instrument transformers. This will ensure continued supply reliability for customers in the Thomastown, Coburg, Preston, Watsonia, North Heidelberg, Lalor, Coolaroo and Broadmeadows service area.	
Glenrowan Terminal Station 66kV CB Replacement	Glenrowan Terminal Station (GNTS) is located in north eastern Victoria and supplies approximately 35,000 customers in the area including Wangaratta, Euroa, Mansfield, Mount Buller, and Benalla. The terminal station has 220kV connections to Dederang (DDTS) and Shepparton (SHTS) terminal stations. The station consists of a 220kV switchyard, 66kV switchyard and two 220/66/22kV transformers. This project will replace five 66kV circuit breakers as part of the preferred, staged replacement option.	**$3.3**
Horsham Terminal Station 66kV CB Replacement	Horsham Terminal Station (HOTS) is located in central western Victoria and supplies approximately 35,000 customers in the area, including in the Grampians. The terminal station has 220kV connections to Red Cliffs (RCTS) and Ballarat (BATS) terminal stations. The station consists of a 220kV switchyard, 66kV switchyard and two 220/66/22kV transformers. This project will replace five 66kV circuit breakers as part of the preferred, staged replacement option.	**$3.3**
Frankston Terminal Station 66kV CB Replacement	Frankston Terminal Station (FTS) is located in central eastern Victoria and supplies approximately 100,000 customers in the area including Frankston and Mornington Peninsula. The terminal station has 220kV connection via Cranbourne (CBTS) terminal station and consists of 66kV switchyard and protection and control room only. This project will replace seven 66kV circuit breakers as part of the preferred, staged replacement option.	**$2.5**
Total		**$155.6**

Source: AusNet Services

4.10 Asset replacement programs capital expenditure

This section describes the asset replacement programs that we propose to undertake to maintain network performance.

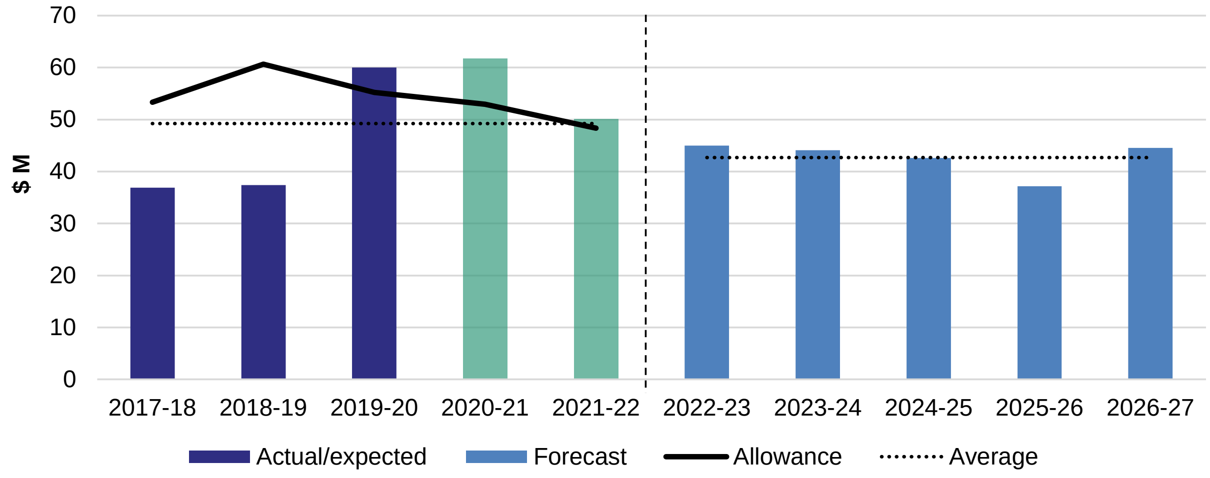
As already explained, significant investment in our network took place in the 1960s and early 1970s as the state-wide grid was established; generation was concentrated in the Latrobe Valley; and the Victorian and Snowy Mountains hydro schemes were integrated. Increasing demand led to the establishment of the 500 kV network in the 1980s. Station assets from the 1960s have largely been replaced. Now assets installed in the 1970s and 80s are displaying signs of deterioration and are approaching the end of their technical lives.

The condition of each asset type (characterised by design, construction materials, manufacturing process, etc) deployed in quantity within the network is assessed for on-going performance. As the condition of these assets deteriorates, their ability to perform to requirements – in terms of being able to provide safe and reliable power – declines, presenting risk to the continued reliability and safety of the transmission network.

To address this risk, we undertake asset replacement programs to replace deteriorated line and tower assets (e.g. conductors), station assets (e.g. transformers and CBs), protection and control systems and communication equipment. Crucially, our decisions to replace an asset are based not just on condition but also criticality, which reflects the reliability, safety, environmental and other consequences of an asset failure. For example, following the closure of Hazelwood Power Station in 2018, we commenced a program to replace circuit breakers in the Latrobe Valley, reflecting the criticality of these assets to the energy supply chain in Victoria.

We are proposing to undertake $213.4 million of expenditure on asset replacement programs in the next regulatory period. This is 13% ($32.8 million) lower than the expenditure we expect to incur in the current regulatory period.

Figure 4–13: Actual, expected and proposed asset replacement programs capex ($M, real 2021-22)



Source: AusNet Services

As with major station projects, asset replacement programs are economic when the consequence of failure exceeds the cost of replacement. However, unlike major station projects, which target the replacement of deteriorated assets at a single location, replacement programs involve the replacement of specific types of assets across our entire network.

The table below sets out the capex forecast for asset replacement programs, by asset type.

Table 4-13: Asset replacement programs ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Lines	9.7	9.7	9.8	10.0	10.3	**49.6**
Stations	10.3	8.7	8.7	8.9	9.2	**45.7**
Secondary and protection	6.3	6.4	6.4	6.5	6.7	**32.3**
Communications	18.7	19.3	17.7	11.7	18.3	**85.8**
Total	**45.0**	**44.1**	**42.6**	**37.2**	**44.6**	**213.4**

Source: AusNet Services

While Plant Strategies for each of these programs have been provided as part of our proposal, we briefly discuss each of these programs in the sections below.

Lines

We are forecasting $49.6 million for lines in the next regulatory period. This comprises expenditure on conductors and ground-wires, power cables and towers.

Conductors and ground wires

Our transmission system contains approximately 6,500 km of conductors, consisting of over 17,300 circuit spans. Our proposed program involves the replacement of conductors, including those in more corrosive environments, that have been identified as being in poor condition and close to end of life.

Ground wires (also known as earth wires) are strung above conductors and plant on lines and stations to shield conductors from lightning strike, reducing outages and possible damage. There are three different types of ground wires (GW) in use on the transmission network: steel, aluminium conductor steel-reinforced cable (ACSR) and optical fibre ground wire (OPGW). As well as protecting conductors from lightning strikes, OPGW offers additional functionality by providing communication links between terminal stations. Our proposed program involves the replacement of ground wires that have been identified as being in poor condition and close to end of life due to corrosion. The ground-wire fleet comprises 7,400 km of ground wire and OPGW, consisting of over 19,300 circuit spans.

The condition of transmission line conductor and ground wire is primarily assessed during tower inspections which are conducted for each transmission structure. The condition data collected is used to develop our asset management strategies and replacement programs.

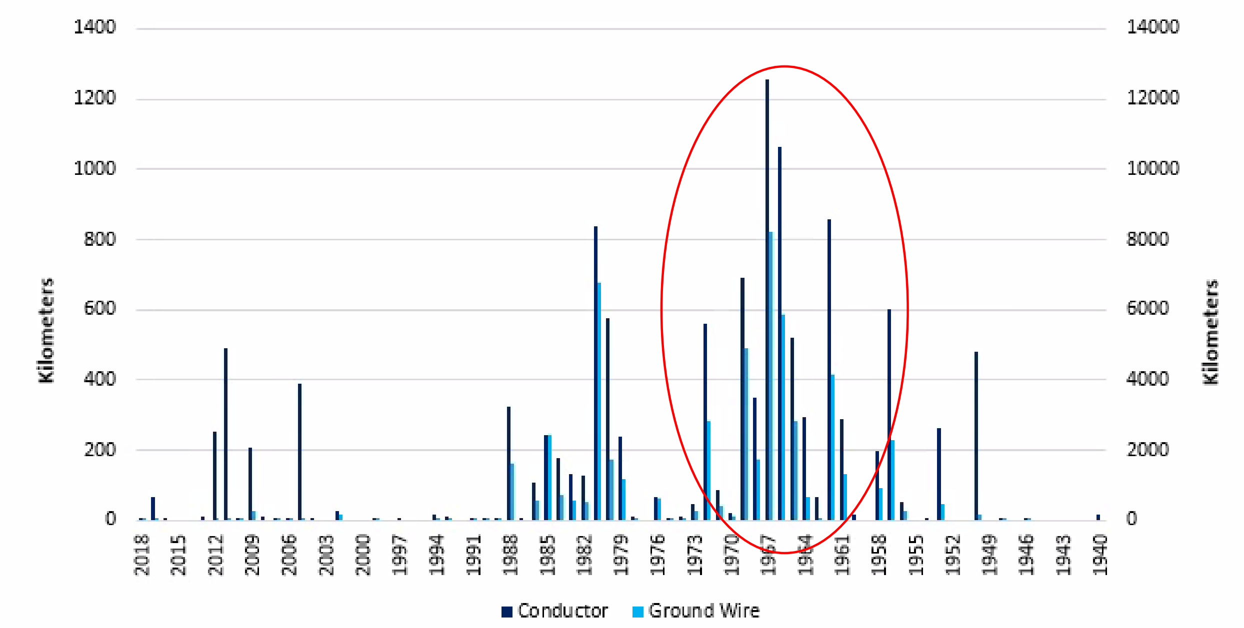
Conductors and ground wires are assigned a condition grade per span on a scale between C1 (best) and C5 (worst) against specific grading parameters. The condition scoring criteria is outlined in an inspection and patrol manual, to ensure consistency. Condition grades focus on factors which are known to adversely affect the electrical or mechanical properties of the assets including corrosion and broken strands.

Our proposed replacement conductor and ground-wire programs, which requires capex of $36.9 million in the next period, will significantly reduce the likelihood of a major failure. The consequences of such a failure include:

- Health and safety incidents;
- Bushfire ignition;
- Financial penalties;
- Significant repair costs;
- Market Impact, affecting generating dispatch;
- Increased risk of loss of supply to many customers; and
- Damage to third party assets.

The increase in conductor and ground wire replacement proposed for the next regulatory period reflects the condition of these aging assets, many of which were commissioned in the 1960s. This is demonstrated by the circled portion of the age profile chart below, which shows that a significant portion of conductors and ground wire were installed on our network more than 50 years ago.

Figure 4–14: Age profile of conductors and ground wires



Source: AusNet Services

Specifically, approximately 55% of the conductor and ground-wire population has been in service for more than 50 years, and this figure will increase to 60% by 2025. Our proposed program will replace 100 conductor and 979 ground-wire spans during the next regulatory period, which account for 0.6% and 5.1%, respectively, of the population of each asset type.

The proposed replacement volumes have been determined using an economic analysis comparing the probability and consequence of failure, with the cost of replacement. As our approach to replacing these assets is based on condition, not on age, it ensures that only those assets that are economic to replace (because of the likelihood and consequence of failure) are included in our forecast.

To assess condition, an improved visual inspection technique, known as Smart Aerial Image Processing (SAIP), was introduced in 2015 and was established as a routine inspection activity in 2020. The SAIP system includes capture of continuous high-resolution conductor images from a helicopter and the use of automatic image recognition technology to locate and prioritise repair and replacement of conductor damage.

This technology enables the efficient capture of conductor images spanning long distances of transmission lines. Images captured are analysed using machine learning software which aims to automate the identification of signs of corrosion including the presence of white powder, conductor bulging or broken strands. This technology will continue to allow us to ensure that future conductor replacements are even more aligned to condition.

Power cables

Power cables are insulated conductors, used in locations where aerial conductor is not feasible. Cables are used on connections between electrical equipment within terminal stations and also in main transmission lines.

We are forecasting $2.5 million for power cables in the next regulatory period. This expenditure is being driven by supply risk and reduction in unplanned remedial repair activities. Strategies to mitigate risks and consequences of a cable failure are proposed. These activities include the acquisition of spare cable and accessories for critical circuits and an on-line monitoring system for the Brunswick to Richmond 220 kV cable (one of the first XLPE insulated long length cable circuits in the world).

Towers

Steel lattice structures make up 96% of structure types on the transmission network. Lattice structures consist of angled galvanised steel members fixed together with bolts. These structures generally support either single-circuit or double-circuit transmission lines comprising the three separated phase conductors per circuit. The phase conductors are protected from lightning strike by single or multiple ground wires between the peaks of the structures.

We are forecasting $4.2 million for towers in the next regulatory period. This is being driven by supply risk and safety considerations due to deterioration in strength from corrosion in some situations, and failure risk of identified tower types under extreme wind conditions. Strengthening of 220 kV towers began in the 1970s, and a program to strengthen targeted early 330 kV transmission line towers commenced in 2016.

As explained in relation to the cost pass-through provisions, a localised severe wind event on 31 January 2020 impacted AusNet Services' double circuit 500 kV transmission line in south western Victoria, causing the collapse of six towers and significant damage to a seventh. The transmission line sections are critical elements in the national grid, including the Vic-SA interconnector, delivering electricity to the aluminium smelter at Portland, and connecting gas and wind generators. Whilst this outcome arose from an uncontrollable storm event, it highlights the importance of expenditure to maintain tower strength.

A program to replace deteriorating bolts and lattice steel lattice members of targeted towers is proposed, with some targeted painting to slow corrosion rates along HYTS-APD 500 kV, ROTS-SVTS 220 kV, and poles along MWTS-LY 66 kV circuits. Four corroded towers in the highly corrosive environment at the end of the HYTS–APD 500 kV Line are also targeted for replacement. The program will continue in the forthcoming regulatory period.

Stations

We are forecasting $45.7 million for stations and plant, outside of the major stations projects. This forecast captures work on the following asset types: power transformers, circuit breakers, instrument transformers, surge arrestors, disconnectors and civil infrastructure.

Power transformers

The proposed power transformers program does not involve the replacement of the transformers themselves, rather, it targets those accessible components of a transformer that have deteriorated and can be individually dealt with. Transformer component failures have the potential to create significant safety hazards for employees, and damage other plant, or cause a much more expensive complete transformer replacement. These lead to a reduction in network security and large replacement costs as well as the safety consequences to employees.

Replacing components will extend the life of a transformer where the core and winding are otherwise in relatively good condition, thus lowering long term costs to customers. We are forecasting $14.4 million for power transformers in the next regulatory period. Our proposed program involves the targeted replacement of bushings (the connection points into the transformer), trialling the on-line monitoring of transformer bushings on market important transformers at SMTS, DDTS and HYTS, targeted replacement of transformer winding temperature indicators, and replacement of Phase Isolated Bus[54] on 500 kV transformers at Hazelwood Terminal Station.

[54] In Phase Isolated Bus, the phase conductors are contained within individual grounded metal housings. The technology is used where space is not available to run a conductor with standard air insulation clearances, and which would present a safety hazard.

Circuit breakers

The failure of CBs will result in unplanned extended outages of the failed CB and may cause adjacent circuit outages due to collateral damage caused by the failure. Failure of bulk oil CBs can also result in explosions and fires. The large volume of oil within the CB tank may spill oil and spread oil fires. Further, failure of porcelain bushings on these CBs can result in projectiles. All of these present a safety risk to our colleagues who work in switch yards.

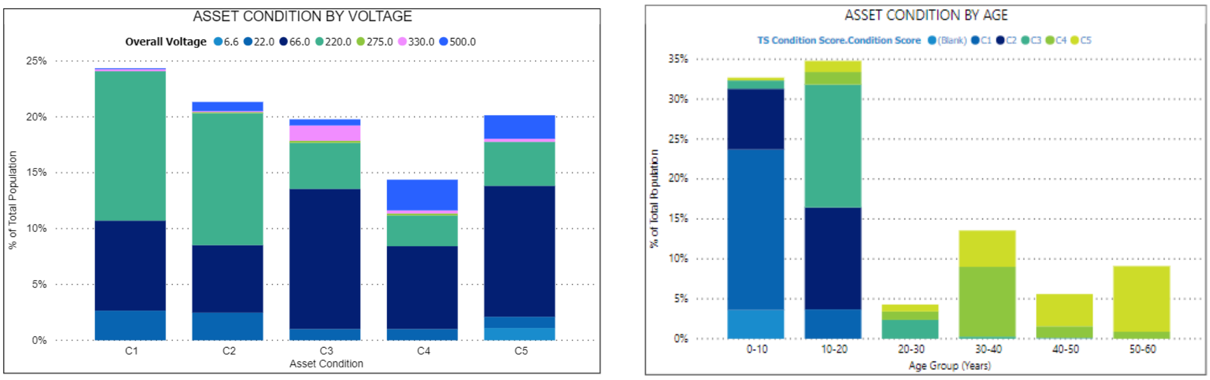
We are forecasting $7.2 million for CBs in the next regulatory period. Our proposed program involves the replacement of 16 CBs which have reached a 'very poor' condition assessment. Other CBs of the same types that are in poor condition will be replaced as part of major station redevelopment works.

Ten of the CBs used to switch capacitor banks will also be replaced. Capacitor bank CBs have a very high switching duty, and the targeted CBs have reached their duty limits and been assessed to be in very poor condition. Some CB refurbishment to extend the life of other CBs is also planned. The CBs included in this program have been determined using an economic analysis comparing the probability and consequence of failure, with the cost of replacement and comparing to any available refurbishment option.

The figure below demonstrates that approximately 20% of the 1,065 in-service CBs are in C5 (very poor) condition and, to maintain safe and reliable supply, need to be replaced. Most of the CBs that are in C5 condition are between 40-60 years of age, demonstrating there is a strong correlation between age and condition for these assets.

The CBs that are proposed to be replaced have substantial deterioration and are approaching the end of their economic lives, which in some cases exceeds the expected regulatory life of 45 years. The maintenance that can be performed to restore the condition is very limited due to lack of availability of spare parts and the fact that these assets are generally no longer supported by the manufacturer. The maintenance of CBs in this category is typically no longer economical compared to asset replacement. We have also adopted a strategy of replacing some assets to generate spares for those that remain in service, enhancing our ability to maintain reliable supply in the event of an asset failure.

Figure 4–15: Circuit breakers by condition and age



Source: AusNet Services

Instrument transformers

Instrument Transformers (ITs) are vital components for monitoring the network current flows and voltages as well as ensuring the network protection operates correctly and safely. Instrument Transformer failures have the potential to create significant safety hazards for employees and damage other plant. These lead to a reduction in network security and large replacement costs as well as the safety consequences to employees.

We are forecasting $8.7 million for ITs in the next regulatory period. Our proposed program involves the replacement of 42 current transformers and 27 voltage transformers types which have reached a poor condition assessment. Other instrument transformers of the same types that are in poor condition will be replaced as part of major station redevelopment works.

To ensure the depreciation schedule for our instrument transformer assets better reflects their economic lives, we are proposing revised asset lives for these assets. This is discussed in Chapter 9.

Disconnectors

Disconnectors (and Earth Switches) are vital components for electrical isolation and earthing of key equipment in the electricity network. They provide safe access to equipment for inspection or maintenance and network operations. Major defects in disconnectors and earth switches cause impairment of their intended functions. Their correct operation is essential to enable operating and maintenance staff to work on plant and switchgear with electrical isolation at earth potential.

Our proposed $1.4 million program involves replacing some disconnectors that have been tagged as poor condition due to poor reliability and health and safety concerns and to create second hand strategic spares where none exist and there is no supplier support.

Surge arrestors

Surge arresters are devices used on electrical power systems to protect critical, or high value items of plant that are susceptible to internal failure due to transient lightning or voltage surges during network switching. Surge Arrestor failures have the potential to create significant safety hazards for employees, and damage other plant, such as much more expensive complete transformer replacement. These lead to a reduction in network security and large replacement costs as well as potentially adverse safety consequences for employees.

We are forecasting $2.12 million for surge arrestors in the next regulatory period. Our proposed program involves the replacement of 57 surge arrestors which have reached a poor condition assessment. Other surge arrestors of the same types that are in poor condition will be replaced as part of major station redevelopment works.

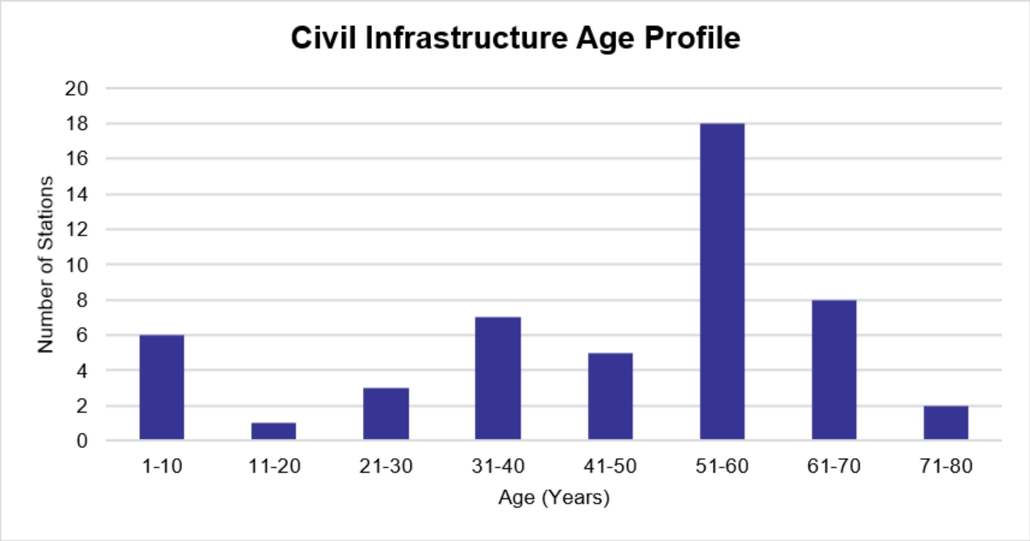
Civil works

Civil infrastructure assets include buildings, roads, footpaths, surfaced areas, foundations, support structures, metallic cabinets, 415-volt supply systems including changeover boards, signage, security systems, fences, cable ducting and trenching, water pipes, fire protection assets, sewerage pipes and drains.

There are varying risks associated with each component of a station’s civil infrastructure, ranging from asset and public safety for the security system/fence, environmental contamination for environmental systems and personnel safety with regards to buildings and switchyard condition. Our civil infrastructure strategy is aimed at ensuring the effective, economic and consistent management of civil infrastructure assets in all terminal stations.

The figure below demonstrates the advanced age of many of our civil assets. Detailed condition-score data on individual civil infrastructure assets is provided in the supporting Plant Strategy.

Figure 4–16: Civil infrastructure age profile



Source: AusNet Services

Condition assessments for civil infrastructure assets at 54 installations, including 42 terminal stations and 12 switchyards inside power stations, indicate that approximately 30 per cent of these assets require refurbishment or replacement within the next 10 years. This can be achieved through targeted civil infrastructure work programs or through planned station rebuild projects.

Depending on the nature and scale of the deficiencies of the civil infrastructure assets, solutions vary from targeted asset replacement, station refurbishment or whole station rebuild. The integration of civil infrastructure upgrades is considered during the scope development phases of such projects as this is typically the most economical solution. The top-down review we undertook has confirmed that no overlap exists between our civil works program and major station projects.

The proposed civil infrastructure program involves the replacement and, where necessary upgrade, of civil infrastructure assets at various terminal stations sites. The condition of civil infrastructure and station facilities at several terminal stations has deteriorated such that they are no longer capable of performing at the required level. Several assets therefore require replacement or upgrade to maintain acceptable levels of risk. We are forecasting \$10.4 million for civil infrastructure in the next regulatory period.

Secondary and protection

This program involves replacement of secondary (protection, control, monitoring and metering) systems and associated direct current power supplies across the Victorian Transmission Network. Equipment to be replaced is primarily located at terminal stations, however, there are some items, such as weather monitoring stations, that can be located on towers.

The approach to replacement of 'end-of-life' secondary systems is to target specific stations where the systems have deteriorated rather than target specific classes of assets. This approach reduces the overall cost of asset replacement as significant synergies can be obtained by replacing multiple assets at one location and the program can be more easily delivered as fewer outages are required.

We are forecasting $32.3 million for expenditure on secondary and protection replacements, outside of major projects.

This expenditure has three key drivers:

- **Modernisation** – Replacement of relays as a progression to a modern standardised design for station equipment using integrated functions in an intelligent device and serial communication. This is becoming more important as the complexity of protection schemes increase markedly to deal with the large increase in intermittent generation sources;
- **Compliance** with the NER and AEMO Protection & Control Requirements (PCRs); and
- **Obsolescence** – Replacement of relays that are inadequate, obsolete, failing, aged or unsupported. Protection system replacements will address reliability risks associated with slow or incorrect operation and deterioration of out-dated electro-mechanical and first generation electronic relays, which do not meet current power system security requirements.

The remaining works will replace failing, non-compliant, unsupported or end of life secondary and protection assets and the continued replacement of battery chargers and DC supply packs.

Communications

Our communications network interconnects various electricity transmission network operating systems, applications and devices. The system has over 3,500 circuits which are used for protection, SCADA, control, signalling, asset data gathering, business computer applications, and telephony systems. The communications network is critical to the efficient and safe operation of the transmission system, as summarised below:

- Protection devices use signalling to constantly exchange information over a communication channel and in the event of an incident, messages are exchanged so that appropriate protection devices operate to protect equipment and minimise the risk of injury.
- Field devices, which include Remote Terminal Units (RTUs), line monitoring devices, and weather stations, send electricity network data to the Supervisory Control and Data Acquisition (SCADA) master or other master server and receive commands from the SCADA master to reconfigure the electricity network through communication channels.
- The telephony system provides voice channels which enable operational teams to talk during periods of emergency or planned network maintenance work, and allow customers to contact AusNet Services to report faults or emergencies.
- Through communication systems, engineers and field teams can remotely access field devices and diagnose network failures or get access to network databases that are used to maintain the network and avoid multiple trips between the terminal station and depots or offices.
- Video surveillance and site access applications are reliant on communication services to protect AusNet Services assets by sending video data to the security centre.

A failure in our communications systems during electricity network fault conditions may adversely affect the duration of outage and the number of customers without supply, as well as causing equipment damage. A lack of communication capacity can also limit the overall capacity available to connect generation, as illustrated by the need for the North West Communications Loop project, which was completed earlier this year.

Our asset management strategy for the transmission communications systems has regard to the asset condition and criticality. Our options analysis for each asset is underpinned by a risk analysis that has regard to the probability of failure and consequence resulting from that failure. In addition, our strategy has regard to:

- **Vendor support**. Due to the rapid advancements in communication technologies, modern equivalents are being introduced in an increasingly shorter timeframe. The knock-on effect is that vendors declare end-of-support for older technologies and spare parts become scarce. Inadequate support negatively impacts the availability of systems to a point where applications that utilise these services are impacted.
- **Legacy Systems**. The communications network is made up of devices from multiple vendors and interoperability challenges arise between different vendors due to the difference in the pace of evolution of technologies by the various vendors. As a result, a change from one vendor in the part of the network may limit the interoperability of the overall network, forcing a technology refresh.
- **Cyber Security**. Utilities are faced with the challenge of building computer networks that withstand cyber-attacks. These attacks can impact the integrity of the electricity network and/or compromise the confidentiality of AusNet Services customer information.

Each of our proposed communications programs has been identified as delivering the lowest costs in net present value terms, having regard to the direct costs and the risk costs associated with each option. The alternative options have also been assessed against a 'base case' option, which involves the replacement of assets on failure. Our approach to assessing options ensures that our proposed communications replacement program is prudent and efficient. In summary, the program will replace communication equipment supporting the electricity transmission network that has reached end of economic life and presents unacceptable risk. The program will ensure we can:

- Continue to monitor the operation of assets and the transfer of information between field operations crews and the control room operators; and
- Minimise the number and duration of outages.

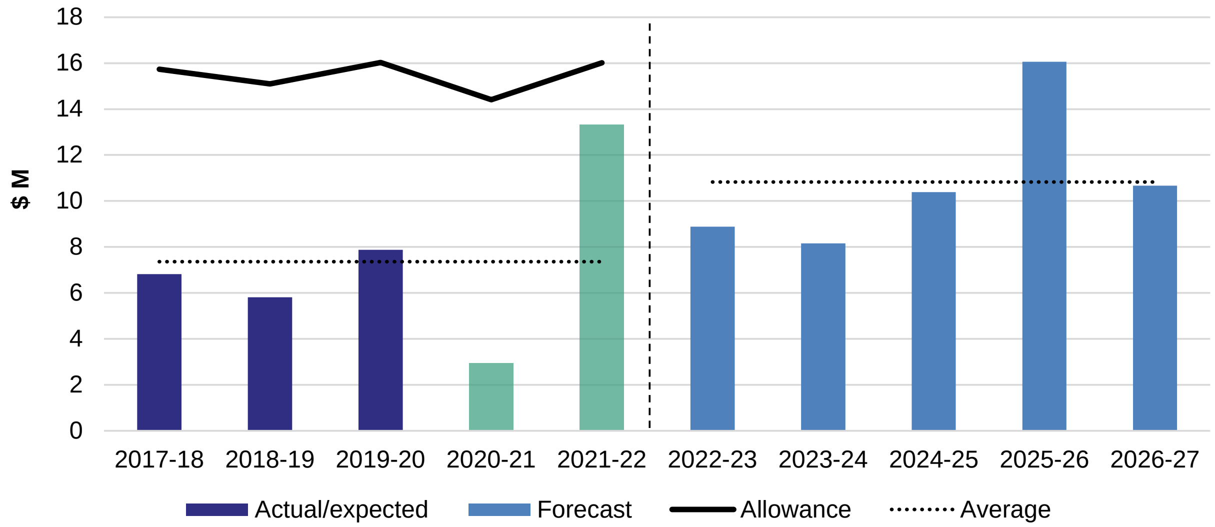
Our proposed program, which requires capex of $85.8 million, involves:

- Replacement of poor condition and increasing unreliable ADSS bearer medium;
- Identification and development of new network architecture (to replace the current Synchronous Digital Hierarchy and Plesiochronous Digital Hierarchy platforms), and the replacement of numerous nodes, switches, routers and serial servers;
- Replacement of point-to-point radios and the design, installation and commissioning of new radio terminals;
- The replacement and capacity increase of systems used to supply direct current, including the installation of new battery banks and replacement of battery chargers; and
- Capital works at several telecommunication sites.

4.11 Safety, security and compliance capital expenditure

We are proposing expenditure of $54.2 million for safety, security and compliance capex. This is 47% ($17.4 million) higher than the amount of expenditure we expect to incur in the current regulatory period. The increased expenditure in 2021-22 reflects a step up in condition-based insulator replacement, in line with the replacement volumes proposed for the next regulatory period. It also reflects expenditure of $5 million to replace ageing equipment at several of our communication sites which, like ICT capex, can be relatively lumpy depending on where the specific assets are within the replacement lifecycle.

Figure 4–17: Safety, security and compliance ($M, real 2021-22)



Source: AusNet Services

This category of expenditure is similar in nature to the replacement programs discussed in the previous section, in that it largely involves the replacement of deteriorated assets that, based on the likelihood and consequence of failure, are economic to replace. Several safety-driven initiatives are also included in the forecast, which are required to meet our safety obligations as set out in the Occupational Health and Safety Regulations 2007.

The table below sets out the capex forecast for safety, security and compliance expenditure by asset category.

Table 4-14: Safety, security and compliance programs ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Fire protection systems	0.5	0.5	0.5	0.5	0.6	**2.6**
Infrastructure security	1.4	1.4	1.4	1.4	1.5	**7.0**
Structure Fall Arrests	0.6	0.6	0.6	0.6	0.6	**2.9**
Insulators	5.6	5.6	5.7	5.8	6.0	**28.7**
Communications (S&C)	0.8	0.0	2.2	7.7	2.1	**12.8**
Total	**8.9**	**8.2**	**10.4**	**16.1**	**10.7**	**54.2**

Source: AusNet Services

Further information on these programs is provided below and in the Plant Strategies provided with this Revenue Proposal.

Fire protection systems

Fire protection systems protect our assets from fire and improve system security and security of supply. A fire in a terminal station's control or relay building could result in a prolonged loss of supply from the station. Similarly, the loss of a major system transformer due to fire could render the system constrained for substantially long durations. Also, uncontrolled fire could result in severe health and safety issues to public and company employee / contractor with possible bush fire initiation.

The main assets covered under fire protection systems are:

- Fire hydrant systems and associated components such as pumps, valves, underground pipes, booster assemblies, water storage tank / dams, etc;
- Fire detectors (aspirating or non-aspirating type) and fire indicator panels;
- Deluge or water sprinkler systems (including heat/ air pressure detectors, operating valve, nozzles, pipeline, etc);
- Fire suppression systems; and
- Fire walls.

We are forecasting $2.6 million for expenditure on fire protection systems. Our proposed program involves upgrading of the fire hydrant systems at seven terminal stations. The work includes the replacement of the old systems, including pipework, and introducing on site water storage to improve fire protection performance.

This program will replace assets which are deteriorating rapidly towards unacceptable condition, whilst ensuring compliance with Australian Standards.

Infrastructure security

Infrastructure Security protects our assets from unauthorised entry (with or without malicious intentions) into the terminal station and control buildings. Unauthorised entry could result in significant damage to assets (intentional or unintentional) impacting system security and the security of supply or personal injury.

A rise in global terrorism has led the Commonwealth and State governments to impose legal responsibility on the owners and operators of critical infrastructure, such as electricity transmission installations, to take all necessary preventative security measures to ensure the continuity of supply. The Victorian *Terrorism (Community Protection) Act 2003* requires electricity and gas providers to develop and monitor risk management plans – including all appropriate preventative security and emergency restoration measures.

The Commonwealth and State Governments have designated selected electricity transmission sites as critical infrastructure, and we maintain more than 75 transmission installations that are subject to security provisions, including terminal stations, equipment fences inside terminal stations, and depots.

We are forecasting $7.0 million ($2022) for expenditure on infrastructure security upgrades in the next regulatory period. Our proposed program involves CCTV and remote operation of switchyard lights at a number of terminal stations, and improvements to security fencing at two terminal stations. This strategy is informed by site specific risk assessments. The 2018 Infrastructure Security Risk Assessment Tool (ISRAT) is used to assess physical security risks to public safety, network assets and the electrical energy they transmit.

Structure fall arrests

Permanent attached fall arrest systems (FAS) provide users with a safe method to access and work from structures while at height. We have approximately 13,000 towers and more than 650 rack and ancillary structures such as ground wire masts and termination masts, which are climbed at least every three to nine years for inspection purposes. The FAS are currently installed on 82% of the transmission line tower fleet and 62% of structures in terminal stations.

Safety continues to be a top priority for AusNet Services. While the electricity industry has an excellent record in relation to tower falls, and consistent with our vision and values, we must continue to invest in this area, as any fall from an elevated position could result in severe injuries or a fatality.

The proposed program for the next regulatory period is a step down from the program we have been delivering in the current and previous periods, which involves the installation of cable-based systems on structures to mitigate the risks associated with working from heights. For the next regulatory period, the structures targeted for completion are terminal stations structures and the transmission line tower fleet structures without fall arrests that require more frequent climbing and that coincide with other asset replacement work planned for those towers.

We are forecasting $2.9 million for expenditure on structure fall arrests, compared with expected spend of $9.2 million in the current period. As discussed in section 4.3, some of the fall arrests installation work forecast at the last reset was not undertaken in the current period due to adopting a new prioritisation approach for installing fall arrests and the introduction of different inspection techniques.

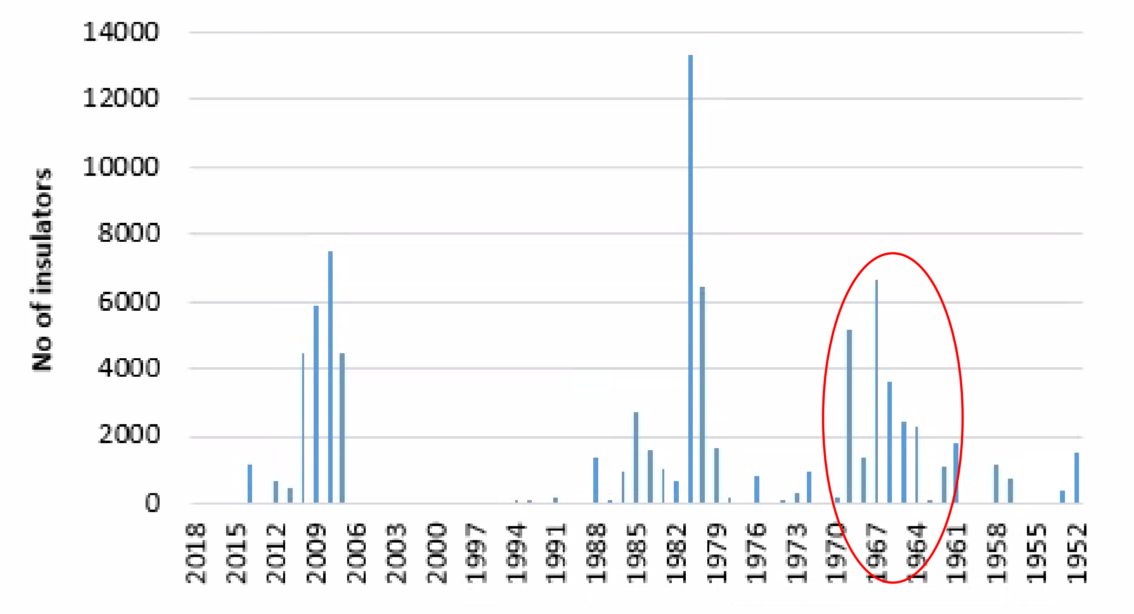
Insulators

Insulators provide a mechanical connection between live conductors and structures while insulating the structures from electrical current. Insulator expenditure has risen and fallen over the last two decades in response to condition assessment and failure history of various fleets.

We are forecasting $28.7 million for expenditure on insulators. While this is a large increase in our proposed expenditure relative to the current regulatory period, it is consistent with expenditure in earlier regulatory periods.

As with conductors, the increase in insulator replacement reflects the condition of these aging assets, many of which were commissioned in the 1960s and are approaching the end of their technical lives. This is demonstrated by the circled area of the age profile chart below, which shows the volume of insulators installed on our network each year.

Figure 4–18: Age profile of insulator assets



Source: AusNet Services

AusNet Services has undertaken a large program of targeted insulator replacements which began in 2006. This program responded to increasing trends in disc insulator functional failures in the period between 2000 and 2007. Since then, approximately 25,000 porcelain insulator strings comprising 29% of the total insulator fleet have been replaced with polymeric insulators since 2006, as is evident from the figure above (i.e. the replacement volumes shown for the years 2006-15).

However, since then relatively few replacements have been needed to maintain reliability and safety. We now need to revisit this area to address the supply and safety risk associated with deterioration of parts of the insulator fleet. In the last three years, there have been two failures involving polymeric insulators on our network. Both polymeric strings were from the same manufacturer, all of which have been removed from service. Some of the replaced samples are currently kept in storage for photo documentation and further testing.

Insulators are currently assessed by visual inspection during condition assessment, and line and easement inspections done either from the ground or a helicopter. Thermal cameras which are primarily used to inspect phase conductors and joints can be used on an ad hoc basis to assess polymeric insulators to identify any 'hot spots' caused in internal arcing.

AusNet Services has developed risk-based models to assist with the application of formal risk assessments as required by the Electrical Safety (Management) Regulations 2019. Approximately 2,328 insulator strings (2.6% of the insulator fleet) are forecast for replacement during the next regulatory period, due to combinations of deteriorated condition, and high failure consequence locations. The volume of insulators to be replaced is low, relative to an age-based indicator for these assets.

Implementation of this selective replacement strategy, addressing both failure frequency and consequences is necessary to maintain public safety and assist in meeting the safety objectives set out in AusNet Services' MissionZero strategy. Importantly, as our approach to replacing insulators is based on condition, this ensures that only those assets that are economic to replace (because of the likelihood and consequence of failure) are included in the insulator replacement program.

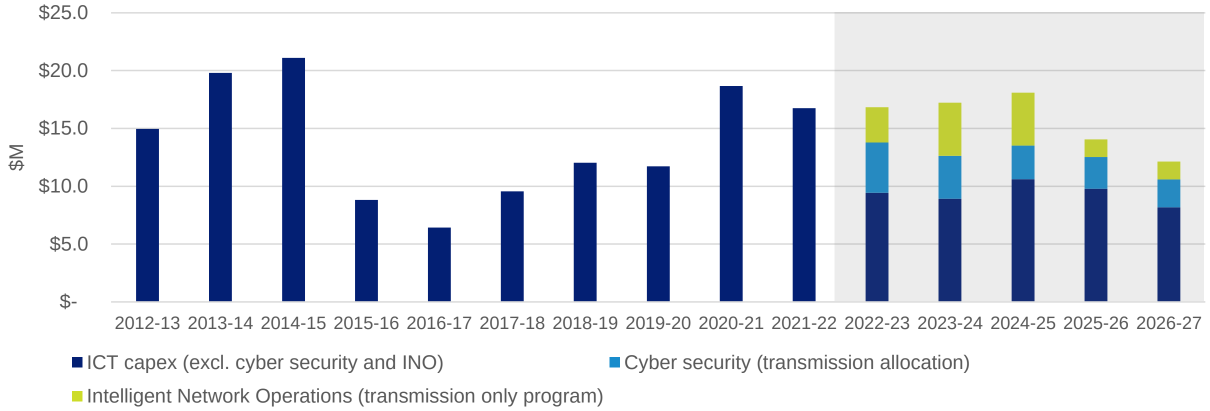
To ensure the depreciation schedule for our insulator assets better reflects their economic lives, we are proposing revised asset lives for these assets. This is discussed in Chapter 9.

4.12 Information and Communication Technology capital expenditure

We are proposing expenditure of $83.8 million for ICT expenditure over the next regulatory period. This is 14% higher ($10.3 million) than the amount of expenditure we expect to incur in the current regulatory period. Except for Intelligent Network Operations, all programs are corporate-wide initiatives that were also proposed in our electricity distribution Revenue Proposal lodged in January 2020. These programs were approved by the AER in its draft decision for our electricity distribution network, which was released in September.[55]

The figure below provides a summary of the forecast expenditure in this category compared with previous regulatory periods. The figure demonstrates that underlying ICT expenditure is in line with long term, historical spend levels, with the overall increase driven by new cyber security requirements and the more complex environment. It also shows that ICT expenditure is cyclical in nature, reflecting the timing of major upgrades (e.g. SAP) and the lifecycle replacement of ICT systems.

Figure 4–19: ICT capex ($M, real 2021-22, direct costs)



Source: AusNet Services

In developing our ICT proposal we engaged external consultants and technology experts familiar with the transmission services environment to assist with the development of a best practice, fit for purpose, technology strategy. Our review has had regard to industry trends, regulatory requirements and business needs. The resulting ICT strategy maintains the continuation of a cautious approach to technology in a complex and uncertain environment that is intended to maintain current service levels and meet new obligations. However, it is also an approach which adopts new technology where the network and customer benefits are demonstrable.

As noted above, we have developed our ICT proposal in a manner that is consistent with the AER's recently introduced framework for assessing the efficiency of proposed ICT investments.

Key drivers of the proposed ICT program

- Our ICT expenditure proposal focuses on addressing the following key drivers:
- **Improving customer outcomes** – our response is to invest in areas which will enable AusNet Services to best deliver tangible outcomes for customers across its business.
- **Cyber security enablement** – this requires us to protect our customers' and business information from cyber threats and attacks.

[55] AER, *Draft Decision – AusNet Services distribution determination 2021 to 2026, Attachment 5 - Capital expenditure*, September 2020.

- **Leveraging and extending investments** – we will realise the full potential of investments by extending the life of core technology assets, working effectively with partners to reduce our ongoing costs and increase efficiency, and taking a cautious approach to prepare for the changes that are expected to emerge.
- **Be future ready** – cater for the increasing demands of integrating renewable generation, by investing prudently in solutions that enhance network management and enable smart transformers, demand management, and network operations optimisation.
- **Increasing digitisation and automation** – leveraging digital technologies such as cloud, automation, and mobility to increase agility and flexibility in the industry's increasingly disruptive environment.

Another driver of our proposed technology investments is to improve efficiency, and so, recognising that our proposed program of work will generate operating efficiencies, we have included a 0.31% productivity saving in our opex proposals (see Chapter 5). Investment to replace and maintain our key technology systems and infrastructure, as well as ensuring our technology capabilities keep pace with the transforming energy system, are necessary to achieve ongoing operating efficiency improvements.

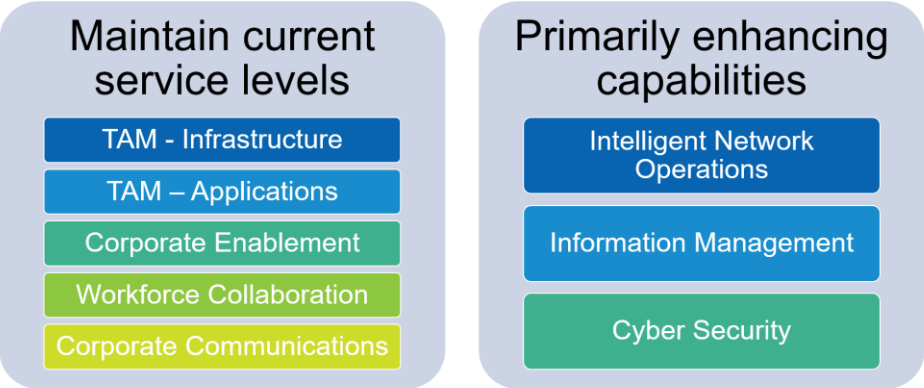
Projects and program of works

Our technology program will enable our transmission business to evolve and to respond to the changes in the operating environment occurring during the next regulatory period. There are eight programs of work, which are split between two key drivers:

- **Maintain Current Service levels** - These initiatives focus on investing in capabilities considering the disruptive environment to optimise and improve capabilities to maintain current service levels; and
- **Enhance Capabilities** – These initiatives aim to enhance or build new capabilities for the organisation to address changes to the Transmission landscape

The categorisation of the programs to each of these drivers is shown in the figure below.

Figure 4–20: Technology program drivers



Source: AusNet Services

The proposed technology programs will deliver critical functionality and serviceability to the transmission business. Seven of the programs also provide benefits aligned to AusNet Services' other regulated network businesses, and the costs are accordingly shared. As noted above, the electricity distribution share of these programs was approved in the AER's recent draft decision for our electricity distribution network. The costs contained in this Revenue Proposal therefore represent the transmission allocation of the seven company-wide programs.

This includes the capex component of our company-wide cyber security program. Our electricity transmission network is a part of Australia's national critical infrastructure. The safety and reliability of electricity supply is integral to powering the lives of Victorians and Victorian businesses. At the same time, the cyber threats to our network are multi-fold and include cyber terrorism, denial of service, extortion and cyber vandalism. These threats are growing as we become more digitally connected for example through the increased number of connection points arising from the growth in the renewable energy generation market.

In recognition of these growing threats, the Australian Energy Market Operator (AEMO), in collaboration with industry and government stakeholders including the Australian Cyber Security Centre, Critical Infrastructure Centre, and the Cyber Security Industry Working Group, has developed the Australian Energy Sector Cyber Security Framework (AESCSF). This framework forms part of a reform package being introduced by the Department of Home Affairs to manage the threat cyber-attacks pose to the wider national and economic security. Supporting legislation is scheduled to be introduced by the end of 2020.

We anticipate that AEMO will impose a regulatory obligation on us as a transmission network provider to uplift our cyber security capability to reach the highest level of maturity of the AESCSF framework, Maturity Indicator Level (MIL) 3, by 2024.

Reaching MIL 3 will impact both capex and opex in the current and forthcoming regulatory periods, requiring a step increase in people, processes and resources needed to monitor, identify, and respond to cyber security attacks. Further information on this program is provided in Chapter 5 and the supporting ICT program brief.

Our ICT proposal also includes an eighth program, the Intelligent Network Operations program, initiated specifically to address the needs of the transmission network. This program is driven by the unprecedented changes occurring in the electricity supply system and the flow-on implications for the transmission network. This transformation continues to gather pace in response to renewable energy targets; lower energy technology costs; and generation retirements. The shift in generation mix toward variable renewable generation requires enhanced power system resilience capability to manage increased system security challenges including frequency, voltage control and stability and system strength.

These power system design considerations also manifest in the network operations activities of the control centre. With the significant shift to renewable generation widely dispersed on the network, a range of operating considerations have become significantly more challenging. The impacts of the more extreme weather patterns that are occurring, including temperature, lightning, wind and bushfire also add to the challenges.

As these influences grow and create new complexities for network operations, we have a priority focus to enhance control centre information and decision-making support systems capability with a greater incorporation of intelligence. These systems are critical to operations activities in two main areas:

(1) Real time operations

- **Maintaining network services** – understanding system weaknesses, and make switching and other operations decisions with best information available on impacts and potential risks to network services
- **Environmental influences** – ability to analyse potential and incipient environmental threats to the network. This activity is currently conducted through passive approaches. Enhanced capability will allow us to maintain efficiency in an increasingly time sensitive environment

(2) Operational and access planning

- Forecasting network conditions and analysing implications – identifying interconnected power system configuration and generation and transmission flow patterns and assessing implications for Victorian network operation and outage planning

- Access planning – planning network outages for maintenance and construction purposes in shrinking windows of opportunity, providing timely information to stakeholders, and optimising outages taking into account the STPIS

In addition, real time operation is mentally demanding, and increasingly so. Improved systems support will provide health and safety benefits for our people and reduce reliability consequence risks.

Our Intelligent Network Operations program will address the emerging challenges on our network and our regulatory obligations by introducing system changes that will:

- Enhance existing network outage planning and network management technologies to better plan and proactively manage the evolving transmission network and provide enhanced capabilities in meeting the Power System Security Rules requirements;
- Upgrade the control room and network operations technologies to utilise the increasing volumes of data, empowering better contextual decision support and situational awareness, and remove manual processes;
- Improve predictive maintenance and provide greater co-ordination of field teams to better manage network outage planning and switching, to enable proactive responses to transmission asset maintenance and events that will allow us to better manage the operational limitations being experienced on the Victorian transmission network;
- Enhance field operations to create efficiencies and provide data for ongoing asset management works; and
- Ensure key control, operational and performance data is captured in digital form to improve operational efficiency and interoperability.

In developing the Intelligent Network Operations program, we undertook the following steps:

- Needs analysis to identify areas of the network and business processes that require investment over the upcoming regulatory period;
- Bottom up discussion with business and technology architects and delivery leads to develop options that address the investment need, including scope, key objectives, and drivers influencing the requirement for the programs;
- Consideration of different options to achieve the objectives of the program and analysis of their relative costs, benefits and risks; and
- A top-down review to ensure that the Technology Strategy investment portfolio represents prudent and efficient expenditure for the upcoming period, relative to AusNet Services' previous expenditure and also benchmarked against other comparable Transmission businesses.

Our preferred option, which maximises net benefit in present value terms, involves the following activities:

- Refresh critical network management systems (e.g. SCADA, Transmission Outage Management System);
- Integrate key systems (GIS, SCADA, SAP), and implement advanced analytics and AI to assist in or automate decision making and real time system restoration; and
- Sharing information across multiple systems to enable us to enhance existing capabilities and new SCADA modules.

As noted in section 4.5 , we tested our justification for this program with stakeholders through a deep dive session. The session explained the rationale for the proposed expenditure and the benefits it is expected to deliver. Whilst a number of questions were raised, the deep dive session did not raise any issues that required us to revise our proposed option.

The table below summarises the eight programs that make up our proposed ICT program, including the Intelligent Network Operations program. Consistent with the AER's assessment guideline, NPV analysis has been conducted for non-recurrent expenditures. The results of this analysis are included in the table below.

More detailed information is contained in the ICT Strategy and program briefs that form part of this proposal.

Table 4-15: ICT forecast capex ($M, real 2021-22)

Program	Categorisation		Description	$M real 2021-22
	Recurrent	Non-recurrent		
Corporate Communications	100%	-	This program ensures the lifecycle management of corporate communications including networking devices (i.e. Wi-Fi, routers), internet services provision and data centre interconnectivity.	**$8.1**
Technology Asset Management - Applications	100%	-	This program ensures the ongoing reliability of critical operations through (amongst others) security patches and bug fixes.	**$3.8**
Technology Asset Management - Infrastructure	100%	-	This program maintains IT systems and helps optimise data centre infrastructure assets, including hardware and licenses.	**$21.2**
Corporate Enablement	70%	30%: Maintaining existing services, functionalities, capability and/or market benefits	This program ensures the ongoing sustainability of core business systems. This includes moving core business functions such as HR and Payroll systems to the cloud and undertaking preliminary work to allow other systems to move to the cloud post the end of the next regulatory period. **NPV of non-recurrent spend**: $7.6M	**$6.2**

Program	Categorisation		Description	$M real 2021-22
	Recurrent	Non-recurrent		
Workforce Collaboration	25%	75%: Maintaining existing services, functionalities, capability and/or market benefits	This program allows teams to access information regardless of location (such as in the field). It will also facilitate collaboration, through knowledge capture and transfer, and improve the accuracy of planning, budgeting and forecasting. **NPV of non-recurrent spend**: $3.9M	**$4.5**
Intelligent Network Operations (Transmission-specific program)	63%	37%: New or expanded ICT capability, functions and services	This program allows us to support and maintain stability and resilience in the Transmission network and field operations in an increasingly complex energy market. Using enhanced network modelling and other key capabilities we will make better decisions, increase our efficiency and continue to deliver reliability. **NPV of non-recurrent spend**: $8.5.M	**$15.9**
Information Management	37%	63%: New or expanded ICT capability, functions and services	This program allows us to analyse network performance in an increasingly complex environment. Using near real time data we will make better decisions, increase our efficiency and continue to deliver reliability. **NPV of non-recurrent spend**: $6.20M	**$7.4**
Cyber Security	45%	55%: Complying with new / altered regulatory obligations / requirements	This program ensures compliance with regulatory requirements. It protects our systems and information from cyber security threats. **NPV of non-recurrent spend**: $31.9M	**$16.8**

Benchmarking and validation

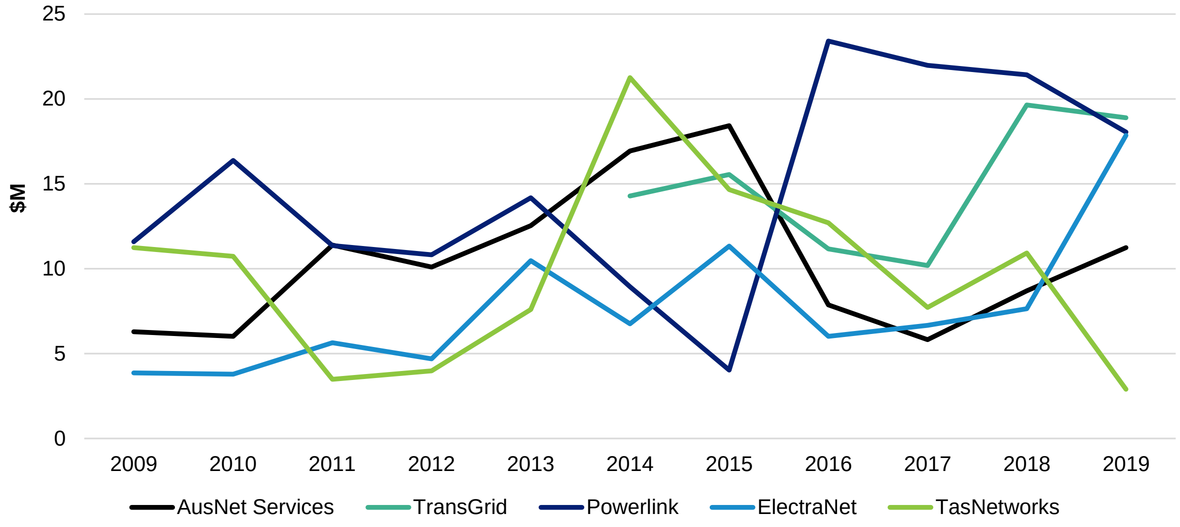
To obtain insight into the key ICT needs, trends and strategic direction of the business, all relevant areas of the business were engaged in preparing our ICT forecasts. We have completed cost and benefit assessments, considering our technology cost allocation methodology which recognises that we are a multi-utility regulated business

External consultants, including Deloitte Consulting and technology experts, were also used to provide industry benchmarks and budget estimates to validate the efficiency of our proposed technology expenditure. Our internal and external experts have also contributed to the development of our Technology Strategy.

Taken together, our approach to ICT gives us assurance that our forecasts are prudent and efficient and are in line with industry best practice.

However, it is important to recognise that ICT expenditure is subject to cycles, depending on the maturity of each company's systems. As shown in the figure below, in recent years our ICT capex has been substantially below most of our peers. The challenges ahead are now better understood and, as a result, it is necessary to now increase investment in the technology capabilities that will allow us to maintain network reliability and safety within a transforming energy system, as well as operate within a significantly worsening cyber security environment.

Figure 4–21: Comparison of historical ICT capex with other transmission networks ($M, nominal, direct costs)



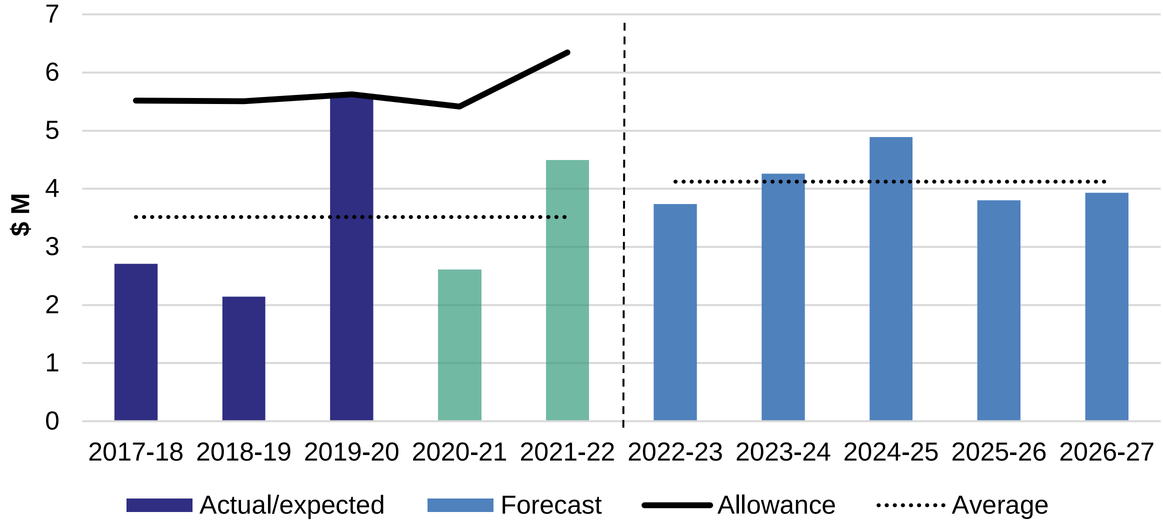
Source: Category Analysis RINs responses

4.13 Other non-network capital expenditure

The 'Other' capex category includes capex on motor vehicles, buildings, tools and test equipment. We are proposing expenditure of $20.6 million for non-network capex (excluding ICT) over the next regulatory period. This is 17% ($3.0 million) higher than the amount of expenditure we expect to incur in the current regulatory period, reflecting modest increases in motor vehicle purchases and buildings capex.

The figure below shows our historical and forecast capex for the different elements of Other capex.

Figure 4–22: Other capex 2017 to 2027 ($M, real 2021-22)



Source: AusNet Services

Key drivers

The expenditure drivers for the 'Other' capex category vary for each of the sub-categories. However, in summary, the principal drivers are:

- Ensuring the safety and well-being of our staff and contactors by providing depots, vehicles and tools that facilitate a safe working environment at all times;
- Minimising total life cycle costs, including optimising the size and age of the vehicle fleet;
- Ensuring that assets are managed in accordance with the relevant asset strategies; and
- Achieving compliance with our statutory obligations.

Projects and program of works

The table below summarises the principal capex projects and programs in this category for the next regulatory period.

Table 4-16: Other non-network capex

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Vehicles	1.2	1.6	1.9	1.2	1.3	**7.2**
Premises	1.9	2.1	2.4	2.0	2.0	**10.4**
Other	0.6	0.6	0.7	0.6	0.6	**3.0**
Total	**3.7**	**4.3**	**4.9**	**3.8**	**3.9**	**20.6**

Source: AusNet Services

Vehicles

Historically we have maintained a fleet of vehicles comprising both owned and leased. These vehicles are used to carry out routine work on the network, to respond to network events, to travel between work sites and to travel to meet stakeholders. We recently shifted to a model where all vehicles are company-owned. The proposed vehicles capex forecast reflects this ownership model, which will require an increase in capex relative to historical levels. This increase has been offset by a reduction in our operating costs, as reflected in our opex base year.

Premises

We own buildings and properties that are used to provide prescribed transmission services and we are responsible for the management and maintenance of those assets. Forecast capex in this area covers expenses such as office modifications including installing portable offices, and accommodation rearrangements, and purchase of office equipment such as desks and chairs. This expenditure will largely continue at historic levels.

Other

The non-network expenditure category of 'other' is comprised principally of capex on tools and measurement equipment. The forecast has been developed based on a historical average of expenditure and reflects the largely recurrent nature of this category.

4.14 Deliverability

Deliverability refers to the ability of the business to deliver the proposed program of work.

In recent regulatory periods, we have a demonstrated our ability to deliver large and complex programs. For example, in the current period we were able to replace, as a matter of urgency CBs in the Latrobe Valley following the closure of Hazelwood Power Station. In addition, we have also successfully delivered:

- Several projects that are crucial to efficiently integrating renewable energy into the system, including a critical upgrade to communications infrastructure in North West Victoria; and
- Two, nearly three highly complex major projects (Project Edison) at the terminal stations supplying the Melbourne CBD and inner suburbs, that are crucial to maintaining long-term, reliable supply to the area (see the Box below).

Box 2: Project Edison: CBD terminal station rebuilds

We have completed two complex brownfield major projects at our terminal stations supplying the Melbourne CBD and inner suburbs (Brunswick 2014 to 2016 completion - Richmond 2012 to 2019 completion) and are well on the way to completing a third terminal station at West Melbourne – begun 2017 and due for completion late 2021.[56]

These three terminal stations are crucial to maintaining long-term, safe and reliable electricity supply to Melbourne's CBD and inner suburbs. Richmond and West Melbourne involve rebuilds of the infrastructure in totality as these were very early built terminal stations and the assets were nearing the end of their reliable operating life. Brunswick Terminal Station rebuild and augmentation was completed at the request of CitiPower and AEMO to further strengthen the electricity network.

Planning for these rebuilds began many years prior, with actual construction at each site only beginning following completion of extensive local consultation and subsequent planning approval. In delivering this work we ensured uninterrupted electricity supply and the safety of all staff and contractors – resulting in very complex interlinked risk managed schedules of works at each site. These rebuilt terminal stations will provide long term reliable electricity supply for our customers for many years to come.

[56] We note that while the WMTS redevelopment project will be operational by this time, it will still require demolition of the 22 kV switchyard, requiring users to migrate from it before this final activity can be undertaken.

Our delivery model for projects includes a mix of internal and external resources. Internal resources undertake much of the design work, project management and quality auditing. External resources include some design consultants and a panel of contractors who provide construction and commissioning services.

This model ensures efficiency by selecting external service providers using a competitive process, ensuring efficient costs and the provision of quality services through competitive tension and robust contractual arrangements.

We will also continue to manage the uncertainty about the need for or timing of projects through the judicious use of external resources. In addition, we have made improvements to our business processes that will improve our deliverability by facilitating better change management, enhanced governance and centralised planning and scheduling. Further information on our project deliverability framework is provided in the supporting document entitled "RIN Supporting Document".

Despite our positive delivery record and our recent improvement initiatives, we have undertaken an extensive deliverability assessment of the proposed program. In particular we recognise the importance of demonstrating that our proposed capex program can be delivered efficiently, noting that it exceeds recent historical expenditure.

In relation to our forecast capex, the economic timing for several large major station projects produced an unsmoothed capex profile that was heavily front-loaded. We concluded that this unsmoothed profile created deliverability risks in relation to:

- The availability of resources (e.g. labour, materials and contractors) required to deliver the projects in a cost-effective manner during periods of peak workload; and
- The ability to schedule the necessary planned outages on the transmission network, which is becoming increasingly difficult due to the operating challenges being experienced on the Victorian transmission network.

To address deliverability risks, we undertook a Deep Dive in August 2020 to seek stakeholder views on how the capex forecast included in this Revenue Proposal should be profiled. In addition to managing deliverability risk, we explained the impact of deferrals in relation to indicative cost and risk impacts.

In light of the stakeholder feedback received regarding the high value placed on both reliability and affordability, it was decided that smoothing the forecast in a way that prioritised supply risk and market impact risk over other risks would best reflect customers' views (see Appendix 3C for a summary of the stakeholder feedback received at Deep Dive 2). In particular, and noting that safety could not be compromised in any deferral decision, projects were ranked to minimise:

- **Supply risk**. The risk of supply being lost to customers due to an asset failure; and
- **Market impact risk.** The risk that due to an outage the lowest cost generators cannot supply the NEM, resulting in higher wholesale prices.

Other factors we had regard to when selecting projects for deferral included:

- **Committed projects**. These projects, which account for 7% of proposed major stations capex, are currently being delivered and on track for completion by the first year of the next regulatory period. Timing for these projects was therefore left unchanged
- **Projects going through RIT-T**. Projects for which RIT-T processes are underway have largely been kept at their economic timing
- **Interactions with the ISP**. Projects where coordination with ISP projects is necessary to minimise total costs to customers have been timed to coordinate with the relevant ISP project (e.g. SYTS project).

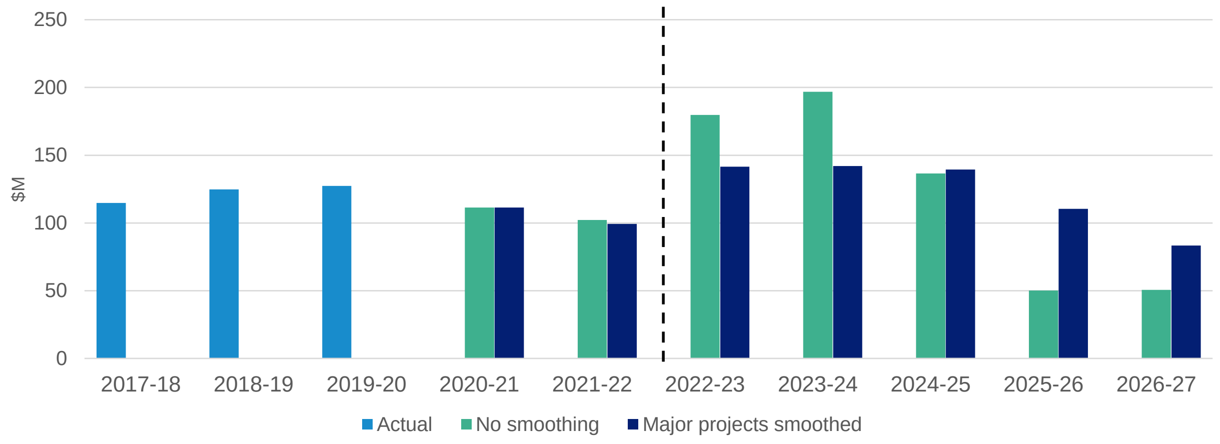
Applying the prioritisation approach described above resulted in the deferral of the following major station projects:

- RCTS Transformer and Switchgear Replacement (**deferred by one year**)
- SMTS 330/220 kV Transformer Replacement - Stage 2 (**deferred by two years**)
- SMTS 500 kV GIS Replacement (**deferred by two years**)
- TTS 66 kV Circuit Breaker Replacement (**deferred by one year**)
- KTS A4 500/220 kV Transformer Replacement (**deferred by two years**).

The project deferrals outlined above have addressed the deliverability risk associated with the capital program, without compromising the reliability and safety of the network and ensuring market impact risk is addressed.

The chart below compares the unsmoothed forecast with the smoothed forecast reflected in this Revenue Proposal.

Figure 4–23: Smoothed and unsmoothed network capex forecast ($M, real 2020, direct costs)



Source: AusNet Services

4.15 Why our capex forecasts satisfy the National Electricity Rules

NER S6A.1.1 requires a Revenue Proposal to identify the categories of transmission services which are to be provided by the assets associated with the capital expenditure forecast. The assets associated with the Hazelwood Power Station 220 kV CB Replacement - Stage 4 project will provide entry connection services. All other assets provide either prescribed shared transmission services to AEMO or prescribed connection (exit) services to Victorian DNSPs.

Among other things, the NER also require the AER to assess the prudency and efficiency of our capex, having regard to ‘capital expenditure factors’. These factors include:

- The AER’s most recent annual benchmarking reports;
- The actual and expected capex in previous regulatory periods;
- The extent to which the forecasts address the concerns of electricity consumers;
- The relative prices of operating and capital inputs;
- The substitution possibilities between opex and capex;
- Whether the forecast is consistent with the applicable incentive schemes;

- Whether the forecast reflects arrangements that are not on arm's length terms;
- Whether the capex forecast includes an amount relating to a project that should more appropriately be included as a contingent project;
- The extent to which we have considered, and made provision for, efficient and prudent non-network options; and
- Any relevant final project assessment report, as required by the regulatory investment test for transmission procedures.

As the AER is required to consider these factors in determining whether it is satisfied that the forecasts reasonably reflect the capex criteria, we have considered all those factors in developing our forecasts.[57] In particular, we note:

- The AER's most recent benchmarking report highlights that AusNet Services:[58]
    - Is the second most improved performer under the AER's preferred total factor productivity measure; and
    - Has improved its capital productivity over the long-term.
- AusNet Services has had the highest transmission asset utilisation in Australia since 2014, as demonstrated by Figure 4–3.
- In addition, data from the AER's 2020 network performance report shows that we have maintained the lowest transmission asset base per customer in Australia over the last decade and have avoided increasing the burden on Victorian customers over time, in stark contrast to other States.[59]
- Our approach to customer engagement in the lead up to and the preparation of this proposal reflects our continued and ongoing commitment to our customers. For example, we have leveraged the customer research and engagement we carried out as part of our recent electricity distribution review. Our proposal also reflects the feedback we have received through our engagement with the CAP and insights we have gained through our day-to-day operations and interactions. We are therefore confident that our forecasts address the concerns of electricity consumers.
- We routinely consider operating and capital input prices and substitution possibilities when developing our business cases. Similarly, we routinely consider non-network options in our project evaluations, and adopt them where it is cost effective to do so.
- Our capex proposals focus on maintaining reliability, which is consistent with the design of the AER's incentive schemes.
- Related party arrangements do not affect our forecasts.
- There are no final project assessment reports currently available in relation to our capex forecasts.

In addition, as explained earlier, our forecasts reflect a robust, analytical approach to asset management. Our approach also has a clear focus on delivering safe, reliable and affordable distribution services. Taken together, we are confident that our capex forecasts comply with the NER requirements and consider that they should be accepted by the AER.

[57] National Electricity Rules, clause s 6A.6.7 (e).

[58] AER, *Electricity transmission benchmarking report 2019*, November 2019

[59] AER, *Network performance report 2020,* September 2020; AusNet Services analysis

4.16 Supporting documents

We have included the following documents to support this chapter:

- Appendix 4A - Unit Rates
- Appendix 4B – Project Cost Estimating Methodology
- Appendix 4C - ICT Strategy
- Appendix 4D – Forecasts of Load Growth (AEMO Transmission Connection Point Forecasts for Victoria).

A significant number of other documents, including the Capex Model, Asset Management Processes and Strategies, Planning Reports, Plant Strategies and ICT Program Briefs, support our capital expenditure proposal.

5 Operating expenditure

5.1 Key points

The key points in this chapter are as follows:

- Our forecast of operating expenditure is a prudent and realistic forecast that allows us to deliver efficient and reliable transmission services, address new regulatory obligations and operate and maintain new growth assets. The forecast achieves the operating expenditure objectives of the NER.
- Our opex forecasting approach follows the AER's established base-step-trend methodology. This results in a forecast of opex that is below the allowance approved for the current period, excluding expected exogenous increases in council rates.
- Efficient base year costs account for 75% of our forecast of controllable opex for the next regulatory period, which is $546 million. Independent AER benchmarking confirms the efficiency of our base year costs.
- We have identified a number of 'step changes' where higher opex is needed to meet new regulatory obligations or deliver initiatives that will result in lower capital expenditure (capex) than would otherwise be case. These opex/capex trade-offs will leave customers better off overall.
- Following consultation with stakeholders and in response to their feedback, we have committed to absorbing some potential step changes, which will help to address our customers' affordability concerns.
- We have included productivity improvements in our forecast as requested by the Customer Advisory Panel.

5.2 Chapter structure

This chapter is structured as follows:

- Section 5.3 provides a summary of operating expenditure forecasts;
- Section 5.4 explains our forecasting approach;
- Section 5.5 sets out how we incorporated customer preferences and feedback in developing our opex forecast;
- Section 5.6 describes our key inputs and material assumptions;
- Section 5.7 details our base year expenditure;
- Section 5.8 explains our approach to rate of change;
- Section 5.9 defines our approach to growth assets;
- Section 5.10 details our step changes;
- Section 5.11 sets out our total controllable opex;
- Section 5.12 explains our non-controllable opex; and
- Section 5.13 demonstrates that our opex forecasts satisfy the Rules requirements.

5.3 Summary of operating expenditure forecasts

Our forecast of operating expenditure is a prudent and realistic forecast that allows us to deliver efficient and reliable transmission services, address new regulatory obligations and operate and maintain new growth assets. The forecast achieves the operating expenditure objectives of the NER.

We work hard to ensure we are consistently ranked as an industry leader in transmission operating efficiency, as shown by independent AER benchmarking.[60] In the current period we achieved significant efficiency savings through our cost efficiency programs, which will lead to approximately $88 million less opex in the next regulatory period.

The application of the base-step-trend approach to our efficient base year opex produces a total opex forecast that is prudent and efficient consistent with AER practice and the expenditure objectives set out in the NER. With customers focusing on affordability, our proposed opex minimises costs while also meeting new regulatory obligations without compromising the reliability and safety of our network services.

Following extensive consultation with stakeholders, we are forecasting total opex of $1371 million (real 2021-22) over the 2023-27 regulatory period. This comprises both opex which is not within our ability to determine (non-controllable opex), and opex is within our control (controllable opex). The total annual opex forecast is set out below.

Table 5-1: Total opex forecast 2022-23 to 2026-27 ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Controllable	111	110	109	108	108	546
Non-controllable	165	165	165	165	165	825
Total opex	**276**	**275**	**274**	**273**	**273**	**1371**

Note: numbers may not reconcile due to rounding.

Non controllable opex makes up $825 million or 60% of our total forecast opex. The majority of non-controllable opex is driven by easement land tax, at $816 million. Easement land tax is a levy applied by the Victorian Government, which is recovered through regulated revenues. Debt raising costs of $9 million make up the rest of non-controllable opex.

Our controllable opex for prescribed transmission services in the forthcoming regulatory control period is $546 million, approximately 29% higher than the actual and estimated controllable opex in the current regulatory control period but well below the allowance because of the savings we achieved in the current period. While this will translate into a $38 increase in opex per customer, it is $28 lower than if we had not realised $88 million less opex and revenue in the current regulatory period.

Forecast increase in opex in the forthcoming regulatory control period compared to historical operating expenditure are due primarily to:

- A number of step changes relating primarily to new or changed regulatory obligations (including a large step up in council rates), in addition to opex-capex trade-offs; and
- An increase associated with the rolling-in of non-contestable prescribed service assets constructed in the current regulatory control period.[61]

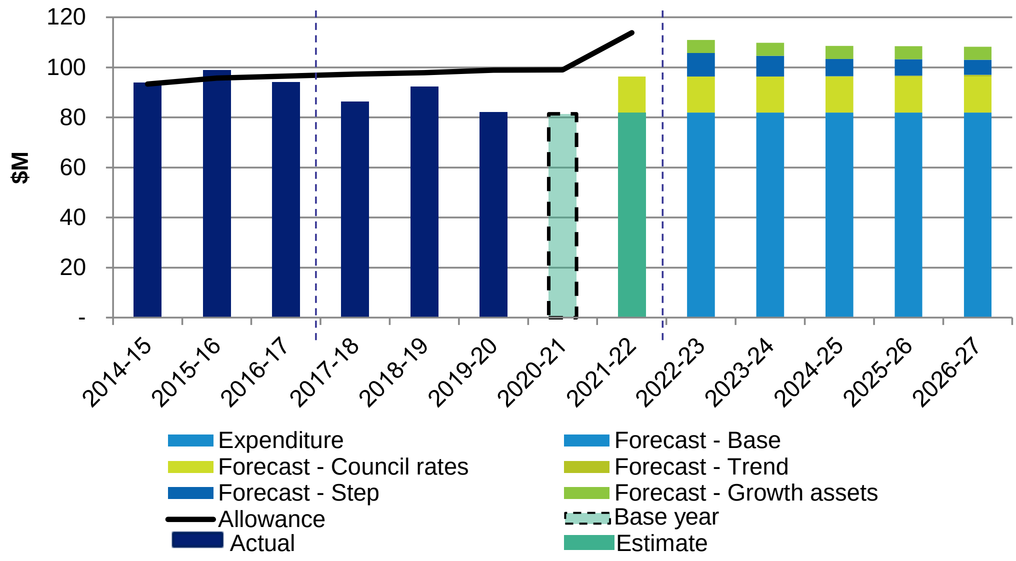
The reasons for these variations are explained in the remainder of this chapter.

[60] See Australian Energy Regulator, *Annual Benchmarking Report: Electricity transmission network service providers* (Nov 2019).

[61] This complies with s6A1.2(8) of the NER.

Actual, estimated and forecast controllable opex for the current and forthcoming regulatory periods is shown in the below figure.

Figure 5-1: Controllable operating expenditure 2014-15 to 2026-27 ($M, real 2021-22)



Note: the 2021-22 allowance has been adjusted to include an anticipated $14.3 million (real 2021-22) in council rates.

Our proposed annual average opex is set out in the table below.

Table 5-2: Average annual forecast controllable opex ($M, real 2021-22)

Opex component	Annual average opex
Base year opex	82.0
Plus	
Rate of change	0.2
Step changes	21.7
Growth assets roll in	5.2
Total	**109.2**

Note: Individual values may not add to total due to rounding. Debt raising costs and movements in provisions are excluded from base year opex. Rate of change includes a negative 0.31 per cent productivity adjustment equating to $0.8 million p.a. See section 5.12.1 for information about Easement Land Tax.

5.4 Forecasting approach

We consider that the revealed cost base-step-trend approach set out in the AER's Expenditure Forecast Assessment Guideline represents an appropriate methodology to forecast opex requirements for an efficient transmission network service provider. We have, therefore, developed our opex forecast on this basis.

- A **base year** of opex is selected that is representative of prudent and efficient costs. For the reasons outlined in section 5.7 below, we consider that our base year opex is efficient. We have also made adjustments to remove non-recurrent costs and incorporate changes in accounting treatments.
- A **rate of change** is applied to the adjusted base year to account for changes in opex trends such as input prices, network growth and productivity.

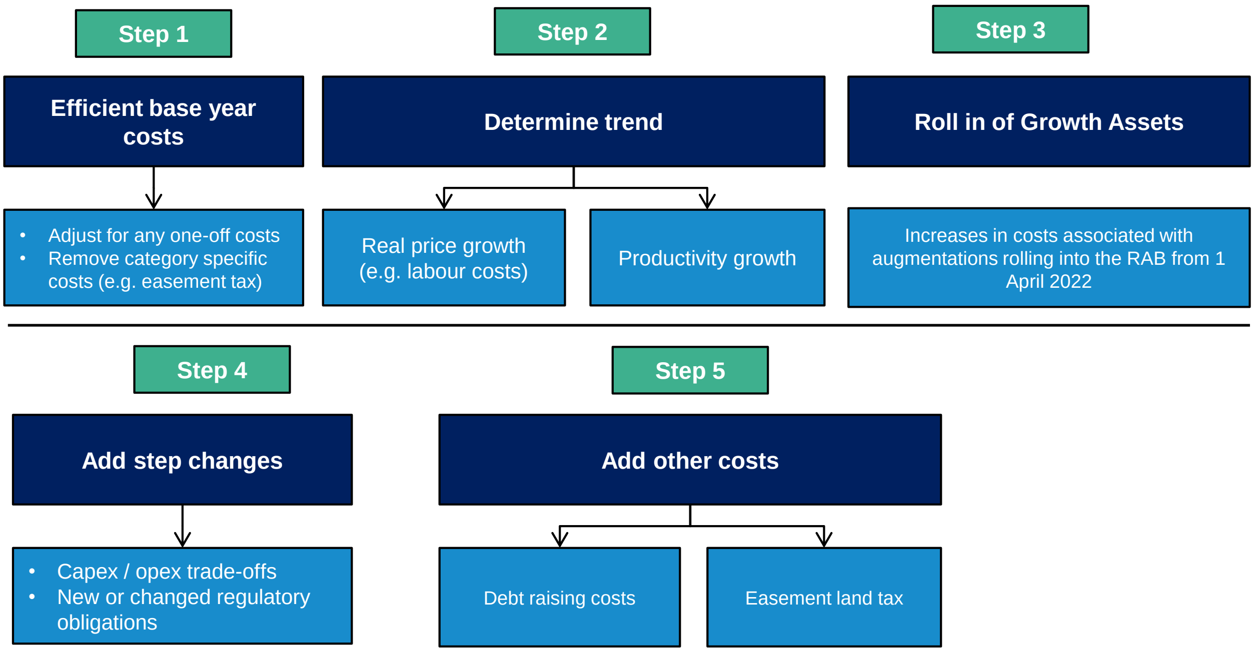
- **Category-specific adjustments** are applied to account for cost increases that are not reflected in the rate of change or any other element of the forecast, such as the roll-in of growth assets.
- Proposed **step changes**, derived using a bottom-up methodology, are added. The proposed step changes reflect changes in regulatory obligations or efficient opex/capex trade-offs.
- **Other costs**, principally debt raising costs and easement land tax, are included as the final element of the methodology.

Our base year costs as well as other costs used to develop the opex forecast have been allocated in accordance with AusNet Services' approved Transmission Cost Allocation Methodology (CAM). AusNet Services' application of the CAM is audited annually during the regulatory accounts approval process.

Our opex forecast will be sufficient to maintain – but not improve – current service performance in dollar terms. That is, the current level of reliability risk, monetised using the value of customer reliability, will be maintained over the forthcoming period. This approach is consistent with AusNet Services' network planning framework and the design of the AER's Service Target Performance Incentive Scheme (STPIS).

The figure below illustrates the forecasting methodology described above, which comprises five steps.

Figure 5-2: Opex forecasting methodology



5.5 Incorporating customer preferences and feedback

As discussed in more detail in Chapter 3 Customer Engagement, we have conducted an extensive customer satisfaction and research program and held Customer Advisory Panel meetings and deep dives with stakeholders on issues important to this review. Affordability emerged as a key concern across all customer groups.

We have considered stakeholder attitudes and expectations as they relate to opex and incorporated this feedback as we developed our proposal. This included conducting deep dives with participants on particular aspects of our opex forecasts such as base year selection and potential step changes.

A key outcome of our stakeholder engagement has been our decision to absorb $4.3 million in additional expenditure over the forecast period to address transformer oil issues and an increase in RIT-T processes. While both these activities reflect efficient costs, we decided to fund them through productivity improvements. By agreeing to exclude these costs from our forecast allowance, we do not benefit from the productivity improvements achieved to fund them; rather, customers benefit immediately.

Other important changes we made in response to customer feedback involved including productivity improvements in our opex forecast and incorporating sensitivity analysis of key inputs relating to our ICT step changes.

The following table sets out the feedback expressed by stakeholders and our responses.

Table 5-3: Stakeholder feedback on operating expenditure

Component	Stakeholder Feedback	Our response
Base Opex	Attendees of our Deep Dive 1 Workshop did not have any criticisms of the overall opex proposal, however they wanted to know more information about particular aspects of the proposal such as whether growth assets include assumptions about future AEMO Integrated System Plan (ISP) projects.	We note that ISP-related projects are procured through AEMO's planning process and are therefore not within the scope of the reset, while growth assets are based on non-contestable augmentations.
Choice of base year	Attendees wanted to understand the factors that may influence our choice of base year being 2019-20 or 2020-21, such as interactions with the EBSS, further 2020-21 actuals, COVID-19, and updated results from the AER's economic benchmarking for transmission service providers.	As customers did not have a strong preference over the choice of base year, we retained 2020-21 as our choice of base year as it is the latest year that actuals will be available prior to lodging our Revised Proposal. We remain revenue neutral as to the choice of base year, regardless of the outcome of 2020-21 expenditure (as this will only affect the split between the EBSS and operating expenditure forecasts) and regardless of benchmarking results. Our Revenue Proposal reflects our most up to date forecast of 2020-21 opex. Actual costs will be available at the time of our Revised Proposal and will be reflected in the AER's final decision. The effects of COVID-19 will be addressed in the Revised Proposal when more information is available.

Component	Stakeholder Feedback	Our response
Step changes	Attendees of Deep Dive 1 noted the following about the cyber security and transformer oil step changes presented to them: • There needs to be clear narrative as to how proposed step change expenditure benefits customers. • It is difficult for attendees to provide any comment on the accuracy or reasonableness of step change expenditure that is of a technical nature. • Step changes could benefit from further analysis on the timing of proposed expenditure as well as sensitivity analysis on the assumptions underpinning the costs and benefits. • Why are proposed expenditures passed onto customers rather than being absorbed by the business as part of business-as-usual activities?	We have updated our business cases to better illustrate the benefits customers will receive from proposed step changes. While there is a valid customer question around how much cost and risk customers and businesses are exposed to, the regulatory framework allows for the recovery of these expenditures, provided it can be demonstrated that it is the most economical solution and the costs are not captured elsewhere in the forecast expenditures. Based on this feedback, we have decided to absorb the potential $2.5 million transformer oil step presented to attendees of Deep Dive 1. We have also incorporated sensitivity analysis of key inputs relating to our ICT step changes.
Council rates	Attendees of our Deep Dive 1 Workshop requested further information about the reasons for the increases in council rates.	Council rate increases are driven by an anticipated change in the valuation methodology to include the value of the capital improvements at each site (i.e. the electricity assets), not just the land value as has been the case to date.
Productivity	The Customer Advisory Panel expressed concern about the zero productivity growth we had assumed in our initial forecast, considering that some level of positive growth should be incorporated.	In response to the issues raised by the Customer Advisory Panel, we included productivity improvements in line with the AER's most recent approach to forecasting productivity for transmission businesses.

5.6 Key inputs and material assumptions

The key inputs and material assumptions underpinning our opex forecast are as follows:

- **Base year opex** has been sourced from AusNet Services' approved 2020-21 budget. More information about the efficiency of the base year is provided in section 5.7.
- **Adjustments** have been sourced from our audited regulatory accounts where available, for example relating to exclusions from forecast opex.

- **Price growth** is based on a forecast of the Wage Price Index (WPI) consistent with the ABS series. We have averaged consultants' reports (from DAE and BIS Oxford) for the final value, consistent with the AER's approach in its recent decision for SA Power Networks. We have leveraged the WPI forecast prepared for the AusNet Services Revised Revenue Proposal for the Electricity Distribution Price Review 2022-26, which was prepared in October 2020 and reflect the impacts of COVID-19 to June 2020. To account for the ongoing impacts of COVID-19, we will commission an updated forecast from BIS Oxford prior to submitting our Revised Revenue Proposal. More information is provided in section 5.8.
- Consistent with the views of the Customer Advisory Panel, we have included **productivity improvements** in line with the AER's most recent approach to forecasting productivity for transmission businesses. These productivity improvements are 0.31% p.a.,[62] reflecting the annual productivity growth rate the transmission industry has achieved over the long term. Further information is provided in section 5.8.
- **Step changes** and category specific forecasts have been forecast using a bottom-up approach with material assumptions provided in the associated opex model. The step changes are discussed further in section 5.10.
- **Growth assets** are included in the RAB in accordance with the regulatory framework according to the value of assets constructed to provide prescribed transmission services during the previous regulatory control period, adjusted for outturn inflation and depreciation. More information can be found in section 5.9.
- Variations in the forecast operating expenditure from historical operating expenditure relate to a significant increase in **local council rates**, which are anticipated to rise from $1 million to $14.3 million per annum. More information is provided in section 5.10.

5.7 Base year expenditure

To ensure the base-step-trend forecasting approach produces a prudent and efficient forecast, an efficient base year must be selected. Efficient base year costs of $410 million account for 75% of our forecast of controllable opex for the next regulatory period.[63] [64]

We have nominated 2020-21 as the base year for forecasting opex. Actual costs are not yet available for this year but will be by the time the AER makes its final determination in January 2022. We considered selecting 2019-20 as the base year, which would incorporate actual costs prior to submission but due to the opex forecasting methodology's interaction with the EBSS, we are revenue neutral as to the choice of base year being 2019-20 or 2020-21. Further, the efficiency incentives provided by the regulatory framework encourage businesses to make continuous opex savings in each year.

The base-step-trend forecasting approach ensures our opex forecast is consistent with the operation of the EBSS in the current regulatory control period and its proposed operation in the 2023-27 period.

Economic benchmarking and category analysis show that we have been the industry leader in operating efficiency relative to our peers. This demonstrates the efficiency of our base year costs and ensures the preliminary opex forecasts is underpinned by an efficient starting point. Our efficiency has been driven in recent years through our refreshed corporate strategy which has a strong focus on operational efficiency. The associated savings we have made in the current

[62] Recent AER economic benchmarking analysis for transmission service assesses that the annual average opex PFP growth rate for transmission networks is 0.31% using the regression methodology.

[63] Controllable operating expenditure excludes easement land tax and an allowance for debt raising costs.

[64] Consistent with AER's up-to-date step trend methodology, we have included insurance within base year expenditure.

period have resulted in $88 million less opex in the 2023-2027 regulatory period. This has been driven by a number of organisational, technological and innovation changes.

Table 5-4: Initiatives resulting in operating efficiency improvements

Efficiency enabler	Example
Organisational	• Outsourcing and automation of key back office functions including many finance and IT components • Outsourcing field resources, ensuring resources are utilised across sectors • Rationalising property, office and vehicle leases • Insourcing inspection and vegetation assessment
Technological and innovative	• Introducing Light Detection and Ranging (LIDAR) based vegetation assessment, which provides laser-based images of vegetation in order to conduct power line clearance assessments • Introducing and expanding high resolution aerial photography (Smart Aerial Image Processing, or SAIP) and combining it with machine learning analytics in order to inspect power lines and detect defects • These technologies, combined with other asset management capabilities enabled by the introduction of SAP and information management platforms, are reducing the frequency of inspections and need for in-person visual inspections and back office analysis

5.7.1 Base year adjustments

To determine a level of base year opex that reflects efficient recurrent expenditure, we have adjusted our opex forecast to account for category-specific drivers of cost increases that are not reflected in the rate of change. This includes:

- Removing movements in provisions to align with the AER's treatment of provisions in its recent transmission determinations; and
- Removing non-controllable costs relating to easement land tax.

By making these adjustments, our forecasting approach ensures the base year opex reflects the efficient recurrent, controllable costs and excludes those cost elements that are outside our control. This approach is consistent with recent AER transmission determinations.[65] It also complies with the operating expenditure criteria in the NER, which require that the opex forecast reflect, among other things, the efficient costs of achieving the operating expenditure objectives.

The table below shows how we have derived this estimate.

[65] *Final decision: AusNet Services transmission determination 2017–22: Attachment 7 – Operating expenditure* (April 2017), p 24; *Final decision – TasNetworks distribution determination 2019–24: Attachment 6: Operating expenditure* (April 2019), p 17.

Table 5-5: Derivation of base year opex ($M, nominal)

Opex component	Amount
Total opex 2021[1]	241.6
Less	
Movement in provisions[2]	-
Easement land tax	161.4
Total opex to be trended	**80.2**

1. Total opex excludes debt raising costs and NCIPAP operating expenditure; 2. Movement in provisions are not forecast, instead they will be populated in the revised proposal once actuals are available.

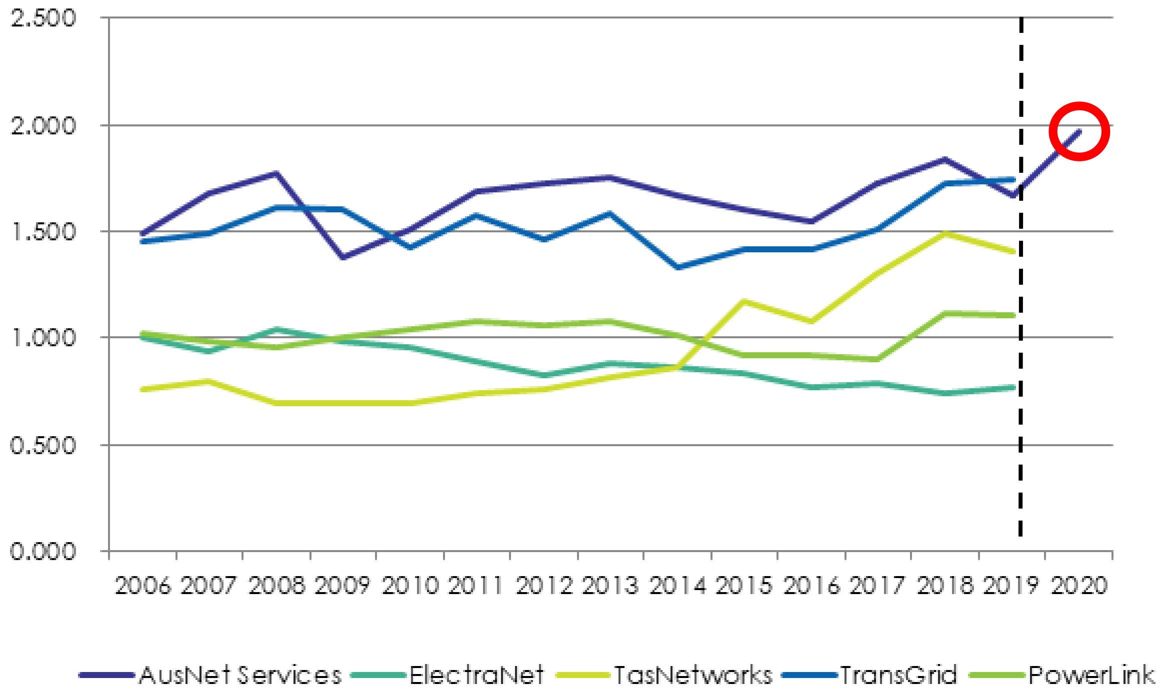
5.7.2 Demonstrating the efficiency of our base year expenditure

Benchmarking analysis of transmission networks is more useful with respect to trends rather than individual ranking because of the significant operating environment differences of transmission networks. Nonetheless, published AER benchmarking shows our productivity performance has been positive over the last decade in contrast with the majority of the network sector, while we have sustained the top rank in terms of opex productivity for most of the last decade.

We have reproduced the benchmarking results using existing AER analysis in Figure 5-3 below. In 2019 our efficiency dropped as a result of one-off circumstances. This was due to both reliability impacts, when one large customer suffered a single outage, and higher opex expenditure driven by one-off costs associated with organisational restructures. Our preliminary analysis of 2020 shows that we expect to return to the highest opex partial factor productivity ranking in 2020.

Combined with our partial performance indicators (discussed next), these results help demonstrate the efficiency of our base year costs and that the preliminary opex forecast is underpinned by an efficient starting point.

Figure 5-3: Opex Partial Factor Productivity Index, actual and forecast



Note: decrease in AusNet Services' 2009 OPFP was caused by an explosive failure at South Morang Terminal Station and a conductor drop on the Bendigo to Ballarat Line.

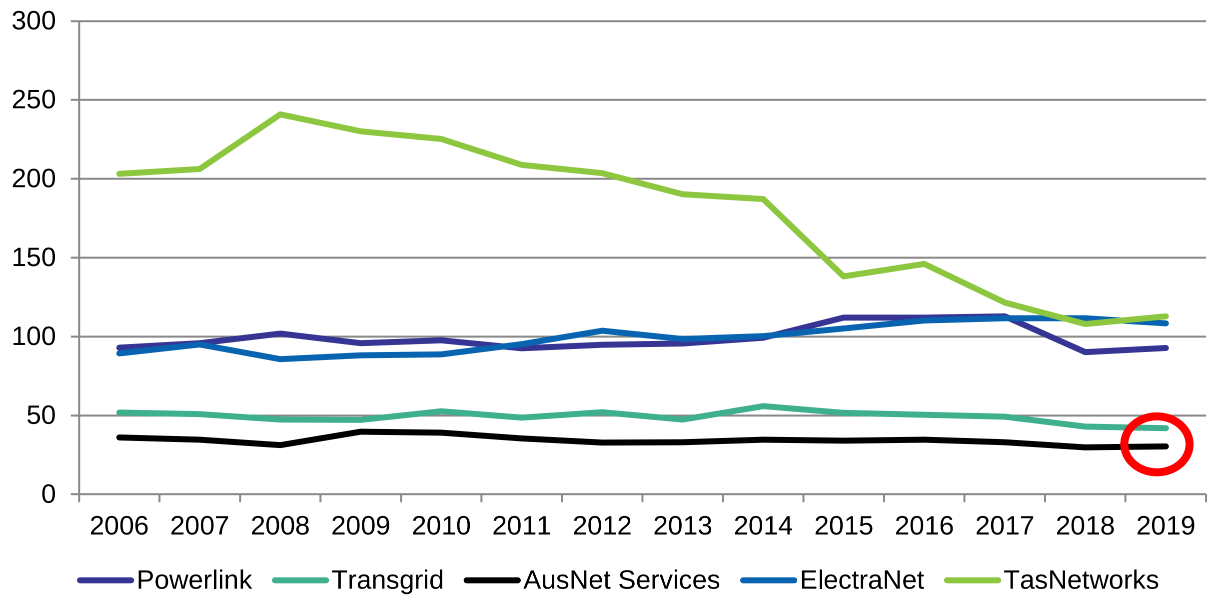
Source: AusNet Services analysis using raw AER Annual Transmission data sourced from publicly available Regulatory Information Notices and internal forecasts.

5.7.2.1 Partial performance indicators

Our efficient performance as measured by opex partial factor productivity is supported by our strong performance across a range of 'bottom-up' partial performance indicators (PPIs) that compare individual opex categories between TNSPs and over time.[66] As discussed by the AER, these PPIs provide a general indication of comparative performance in delivering one type of output. Strong performance across both partial measures is indicative of an efficient level of total opex.

More importantly, the indicators demonstrate that Victorian customers have paid some of the lowest costs to fund transmission operating costs in Australia over the years.[67] The figure below shows that since the start of this data set in 2006, we have consistently produced some of the lowest total cost per customer of NEM transmission network service providers.

Figure 5-4: Opex per end user, 2006–2019 ($M, real 2021-22)



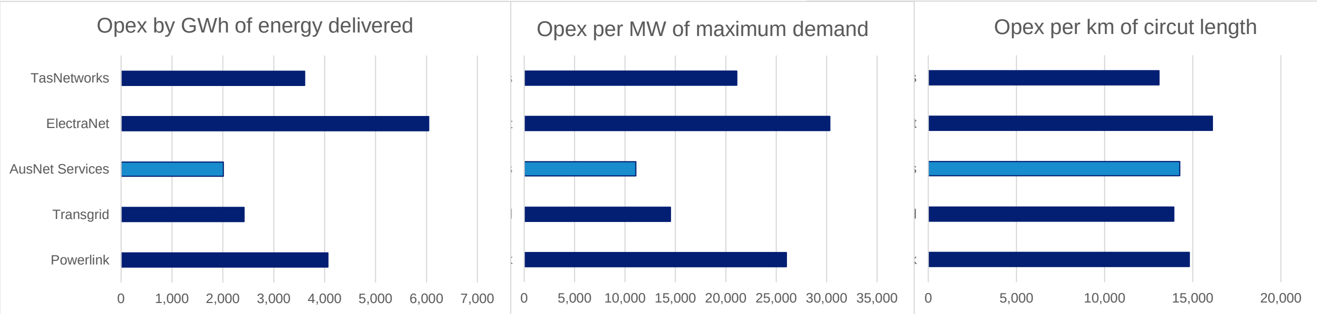
Source: AER, *Electricity network performance report 2020* (September 2020); AusNet analysis.

When considering our performance under other PPIs, the figure below shows that AusNet Services consistently benchmarks well against its peers over a sustained period of time. Over a ten year period, we recorded the lowest opex per Gigawatt hours (GWh) of energy delivered, the lowest opex per MW of coincident maximum demand, and the third lowest opex per km of circuit length by a small margin (less than 3% variation from the second lowest ranked network). These results evidence that we have an efficient level of total opex.

[66] Australian Energy Regulator, *Electricity Network Performance Report 2020* (Sep 2020), p 16.

[67] Ibid, p 17.

Figure 5-5: Opex relative to AER output growth measures average 2010-19 ($M, real 2021-22)



Source: AER, *Electricity network performance report 2020* (September 2020); AusNet analysis.

5.8 Rate of change

The rate of change is applied to base year opex for each year of the forthcoming regulatory period. It captures the year-on-year change in efficient expenditure due to forecast changes in output levels, prices and productivity (such as economies of scale or labour productivity).

In line with the AER's Expenditure Forecast Assessment Guideline, the rate of change is calculated according to the following formula:

Rate of change = output growth + real price growth – productivity growth

The table below summarises our proposed rate of change escalators.

Table 5-6: Forecast rate of change

	2022-23	2023-24	2024-25	2025-26	2026-27
Output growth	0	0	0	0	0
Real price growth	0.30%	0.28%	0.48%	0.68%	0.68%
Productivity change	0.31%	0.31%	0.31%	0.31%	0.31%
Rate of change, yoy	-0.01%	-0.03%	0.17%	0.37%	0.37%
Rate of change, cumulative	**-0.01%**	**-0.04%**	**0.13%**	**0.49%**	**0.86%**

The opex criteria state that the AER must accept total the opex forecast if it is satisfied that the total forecast operating expenditure reasonably reflects, among other things, a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives. For the reasons set out in the remainder of this section, we consider the proposed rate of change is consistent with the opex criteria.[68] The remainder of this section details each component of the rate of change.

[68] National Electricity Rules, clause 6.5.6(c)(3).

5.8.1 Output growth

The opex forecast for the upcoming period does not account for system growth as these costs are initially handled outside of the revenue cap because of the division of TNSP functions in Victoria. Therefore, consistent with the AER's final decision for the current regulatory period,[69] we have not included an output growth component in our opex forecast.

5.8.2 Real price growth

This parameter accounts for the expected increases in labour rates as well as escalation in the price of materials. We have applied benchmarked input price weights of 70.4% for labour prices and 29.6% for materials costs, consistent with the 2017 annual benchmarking report[70] to determine the real price growth parameter in accordance with recent AER decisions.[71]

5.8.2.1 Labour escalation

Given the latest data available at the time of submission, this forecast does not capture the later economic impacts of COVID-19, such as the imposition of a second Stage 3 lockdown and subsequent Stage 4 lockdown declared in parts of Victoria from early July. Therefore, for this Proposal the forecast is simply a placeholder that will be updated in our Revised Revenue Proposal.

When updating the forecast real price growth, we will use the AER's standard approach of adopting the average of the forecast labour price growth supplied by our consultant, BIS Oxford Economics, and the AER's consultant, Deloitte Access Economics (DAE).[72] This is consistent the AER's recent determination for SA Power Networks and referred to in the AER's recent draft decisions for the Victorian electricity distribution networks.[73]

We rely on advice from BIS Oxford Economics as it is one of Australia's leading providers of industry research, analysis and forecasting services. They have built up a rigorous forecast of expected labour price growth in the Electricity, Gas, Water and Waste Services (EGWWS) sector in Victoria based on expected macroeconomic and state specific factors.

We have leveraged the WPI forecast that will be submitted in the AusNet Services Revised Revenue Proposal for the Electricity Distribution Price Review 2022-26, which was prepared in October 2020 and reflects some impacts of COVID-19 to June 2020.

BIS Oxford's findings show that:

- COVID-19 has plunged the Australian economy into recession in 2020 with Australian GDP expected to contract contracting -0.2% % in 2019-20. It is forecast to decrease a further 2.7% in 2020-21, before recovering to 4.2% in 2021-22.
- While the labour market is expected to weaken, utilities sector wages are expected to remain higher than the national (all industries) average. This reflects a highly skilled

[69] Australian Energy Regulator, *Final Decision: AusNet Services transmission determination 2017–22: Attachment 7 – Operating expenditure* (April 2017), p 32.

[70] See *Economic Insights, Economic Benchmarking Results for the Australian Energy Regulator's 2017 TNSP Benchmarking Report*, 6 November 2017.

[71] Australian Energy Regulator, *TasNetworks transmission determination 2019 to 2024* (April 2019).

[72] See *AusNet Services - TRR 2023-27 Model WPI calculation - 29 October 2020*.

[73] See *Final decision – SA Power Networks Distribution Determination 2020–25: Attachment 6: Operating expenditure* (June 2020), p 13-15; see, e.g., *Draft decision – AusNet Services Distribution Determination 2021–26: Attachment 6: Operating expenditure* (September 2020), p45-46.

workforce, strong union presence, competition for skilled resources from the mining and construction industries and fewer skilled workers being trained.

- The overall national average is also expected to be lower due to COVID-19 impacting lower skilled sectors such as the Retail Trade, Wholesale Trade, Accommodation, Cafés and Restaurants. However, the EGWWS sector is not anticipated to be impacted in the same way due to its obligation to provide essential services and to therefore retain skilled labour.
- This utilities sector wages premium has been more pronounced in Victoria to date. However the Victorian EGWWS WPI is forecast to decline more than the Australian EGWWS WPI average in 2020-21 to 2022-23 before recovering in 2023-24 and 2024-25 and weakening in 2025-26, with higher EBA outcomes in Victoria's utilities compared to the national average limiting declines.[74]

To account for new information, including the ongoing impacts of COVID-19, we will commission an updated forecast from BIS Oxford prior to submitting our Revised Revenue Proposal.

Superannuation

Under amendments to section 19 of the *Superannuation Guarantee (Administration) Act 1992* (Cth),[75] the superannuation guarantee is scheduled to increase progressively from 9.5% on 1 July 2020 to 12% on 1 July 2025, as shown in the table below.

Table 5-7: Change in superannuation guarantee charge (%)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27
Superannuation Guarantee charge (%)	**9.5**	**10.0**	**10.5**	**11.0**	**11.5**	**12.0**	**12.0**

Source: Australian Taxation Office

In the draft decisions for the Victorian electricity distribution networks, the AER accounted for legislated increases in the superannuation guarantee in the labour price growth forecasts. This involved factoring in a decrease in labour growth before adding the legislated superannuation guarantee increases to the WPI growth forecasts.[76]

As a result, we have adopted the AER's approach, removing a potential Superannuation Guarantee step change we had originally included and presented to stakeholders.

5.8.2.2 Materials escalation

Non-labour costs comprise a range of cost categories, including materials, motor vehicle expenses, media and marketing costs, as well as land and building leases. As noted above, these materials costs account for around 30% of base opex based on benchmarked input price weights. For the 2023-27 regulatory period, we forecast that these costs will increase at the same rate as CPI. In our view, this forecast is the best estimate of the efficient costs that a prudent transmission network service provider would incur for non-labour costs over the forthcoming regulatory period.

Accordingly, we forecast no real change in non-labour costs for the forthcoming regulatory period.

[74] *AusNet Services - TRR 2023-27 Appendix 5D BIS Oxford Economics Labour Price Forecasts - 29 October 2020*.

[75] See the *Minerals Resource Rent Tax Repeal and Other Measures Act 2014, Schedule 6—Superannuation Guarantee Charge percentage*.

[76] See *Draft decision – AusNet Services Distribution Determination 2021–26: Attachment 6: Operating expenditure* (September 2020), p48.

5.8.3 Productivity growth

The rate of change formula should account for expected changes in industry-wide productivity over the forthcoming regulatory control period to ensure opex forecasts reflect prudent and efficient costs. This average level of productivity will differ from the productivity improvements that individual TNSPs may be able to achieve through implementing efficiency saving initiatives, rewarding outperformance and penalising underperformance as intended under the EBSS.

Having established that our base year opex is efficient, the productivity component of the rate of change should reflect this position on the 'efficiency frontier'. Further, to avoid double counting, the productivity forecast should not account for any productivity improvements that have been compensated for in the real price change and output growth components of the rate of change.

Therefore, consistent with the AER's preferred methodology and the views of the Customer Advisory Panel, we have included a forecast of productivity improvements of 0.31% per annum in our forecast opex. The forecast growth in productivity reflects the annual productivity growth rate that the transmission industry has been able to achieve over the long term and as such is a reasonable estimate of productivity growth in the upcoming regulatory period.

Table 5-8: Forecast productivity change ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Productivity change (%)	0.31	0.31	0.31	0.31	0.31	
Productivity change ($)	**0.25**	**0.51**	**0.76**	**1.0**	**1.3**	**3.80**

5.9 Growth assets

As discussed above, we have not applied any future output growth as this is contracted outside of the revenue cap due to the planning split in Victoria. However, where these contracted assets are for prescribed non-contestable services, it is intended they roll into the RAB at the first available reset.

Therefore, the regulatory framework provides for the RAB to be increased by the value of assets constructed to provide prescribed transmission services during the previous regulatory control period, adjusted for outturn inflation and depreciation.

The inclusion of growth assets in the RAB requires that a corresponding opex allowance must be provided in the building block calculation to reflect the additional assets that must be operated, maintained, monitored and condition assessed.

Consistent with all previous Victorian decisions, we have included a category-specific forecast to fund the operating and maintenance costs of augmentation undertaken at the request of AEMO or a distribution business during the current or prior regulatory control periods.

It is important to note that this arrangement is a transfer of existing costs rather than new costs being passed on to customers. Therefore, it does not impact the current price being paid by customers. Currently, AEMO and the Victorian distribution businesses fund and pass these costs onto customers. Once the assets roll into our RAB, we fund the operation and maintenance of growth assets through our regulated opex allowance.

We have forecast the roll-in of growth assets opex in accordance with current recovery rates specified under existing contracts with AEMO and Victorian distribution businesses. In a small number of cases where these recovery rates are not available (unknown projects), we have applied the average percentage of known growth assets opex as compared to the total roll in amount (equalling 1.4%) to the unknown projects to determine the associated opex. A full list of projects to be included in the RAB for this determination and details of the associated opex charges provided for in these contracts are provided in Appendix 5A Growth Assets.

The table below shows we forecast opex of $26 million associated with the roll in of growth assets. This accounts for 6% of the controllable opex forecast, while the growth assets represent 8% of the total RAB.[77]

Table 5-9: Forecast opex impact of Growth assets ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Opex impact	**5.2**	**5.2**	**5.2**	**5.2**	**5.2**	**26.2**

Note: numbers may not reconcile due to rounding

5.10 Step changes

We are proposing a number of step changes for opex in addition to the base costs for new or changed regulatory obligations and efficient capex / opex trade-offs.

These step changes and their associated drivers are summarised in the table below, with most being driven by new regulatory obligations. These step changes, which account for 7% of the total opex forecast, are discussed in more detail below.

Table 5-10: Opex step changes ($M, real 2021-22)

Step change	Driver	Total over 5 years
Council rates	New regulatory obligation	71.5
Cyber Security	New regulatory obligation	27.9
5 minute settlement rule change	New regulatory obligation	3.9
Environmental Protection Act	New regulatory obligation	3.2
Cloud	Capex/opex trade-off	2.3
Total		**108.6**

In addition to these step changes, we may introduce a step change for additional costs incurred as a result of changes to the transmission ring-fencing guideline. We will assess the need for this step change once the AER's review is more advanced.

In response to stakeholder feedback and internal assessment, we have elected to absorb step changes, which has reduced our opex forecast by a combined $4.3 million over the forecast period. These step changes are:

- $2.5 million for Transformer Sulphur oil regeneration works driven by an efficient capex/opex tradeoff; and
- $1.8 million for resourcing required for new RIT-T obligations relating to transmission replacement projects.
- Stakeholders raised affordability concerns and queried whether the proposed costs should instead be funded by the business as part of 'business as usual' expenses.[78] These additional costs will be incurred and are efficient but following further internal review, we have committed to absorbing the associated increases in opex due to affordability concerns.
- Lastly, we removed a proposed $1.8 million Superannuation Guarantee step change as this is now accounted for in the rate of change in alignment with the AER's draft decision for the Victorian electricity distribution businesses (see section 5.8.2.1).

[77] See *ANT - TRR 2023-27 Model Document Growth Assets calculation - 29 Oct 2020 CONF.*

[78] See Seed Advisory, *Deep Dive Workshop One – Summary Report1: AusNet Services Transmission Revenue Reset 2023 – 2027* (July 2020).

5.10.1 Council rates

We have included a step change in council rates. This cost category is expected to rise from $1 million to $14.3 million per annum due to a change in the methodology used to value terminal station assets.

Originally, following guidance from the Victorian Valuer-General, we expected the increase in council rates to occur in 2020-21. However, the new methodology does not appear to have been used in calculating rates for 2020-21 and the council notices issued for 2020-21 do not reflect the expected rate increases. We continue to work with the Government to clarify when the new valuation methodology will commence. As part of this we have written to the Valuer-General and requested a response and will keep the AER informed of any updates. If the expected increases materialise prior to 1 April 2022, we will submit a cost pass-through application to the AER to recover the increased cost.

A cost increase attributable to higher council rates meets the AER's definition of a forecast opex step change as it is an exogenous change in the scope or scale of required opex driven by a new compliance requirement. The step change is allocated to the Taxes and Charges expenditure category and we have categorised this program as recurrent expenditure, on the basis that it relates to an ongoing compliance requirement with periodic expenditure. It does not result in an increase in the output growth parameters nor does it deliver productivity benefits to us as it is a compliance-based program.

The table below provides our forecast expenditure.

Table 5-11: Council rates step change ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Council rates step change	**14.3**	**14.3**	**14.3**	**14.3**	**14.3**	**71.5**

Note: numbers may not reconcile due to rounding

5.10.2 Cyber security

Our electricity transmission network is a part of Australia's national critical infrastructure as defined under the *Security of Critical Infrastructure Act 2018* (Cth). The safety and reliability of electricity supply is integral to powering the lives of Victorians and Victorian businesses. At the same time, the cyber threats to our network are multi-fold and include cyber terrorism, denial of service, extortion and cyber vandalism. These threats are growing as we become more digitally connected with our customers and increase remote access to operational systems.

In recognition of these growing threats, AEMO, in collaboration with industry and government stakeholders including the Australian Cyber Security Centre, Critical Infrastructure Centre, and the Cyber Security Industry Working Group, has developed the Australian Energy Sector Cyber Security Framework (AESCSF).

The Commonwealth Department of Home Affairs recently concluded a public consultation on a proposal to introduce an enhanced regulatory framework that increases the security and resilience requirements of Australia's critical infrastructure.[79] As part of this framework, we expect the Department will impose new regulatory obligations on us as a transmission network service provider to uplift our cyber security capability. Early indications are that this will be a positive security obligation supported by sector-specific requirements, which we anticipate will require us to reach the highest level of maturity of the AESCSF framework – Maturity Indicator Level (MIL)

[79] Department of Home Affairs, *Protecting Critical Infrastructure and Systems of National Significance: Consultation Paper* (August 2020).

3 – by 2024. The indicative timing for the introduction of these obligations is this year, although this timeline may be subject to change.

In its recent Draft Decision for AusNet Services' distribution electricity network, the AER noted 'the current context of evolving threat of cyber security risk, and the Australian Government's recent warning to organisations to take action to mitigate these risks of increased frequency and sophistication of cyber-attack.'[80]

Reaching MIL 3 will impact capex and opex in the current and forthcoming regulatory periods. It will require a step increase in people, processes and solutions needed to monitor, identify, and respond to cyber security attacks. The capital expenditure component of this program is discussed in Chapter 4.

By upgrading the security of critical systems and supporting processes which manage, monitor and control the network, our proposed cyber security program will ensure we continue to meet basic customer expectations of our network in line with the increasing risk. This will include undertaking a number of critical programs of work to proactively detect and deter threats, as well as uplifting overall governance and access controls, while maintaining the security and privacy of customer data.

In addition to satisfying emerging regulatory requirements, this program will provide a number of quantifiable customer benefits, including avoiding or reducing:

- Loss of supply to customers arising as a result of a cyber-attack shutting off energy supply;
- Risk of system failure requiring remediation, including activities to restore systems, data and supporting processes impacted by a cyber security attack;
- Risk of system failure to public assets. This includes activities to restore or repair public assets suffering damage due to a cyber security attack. This could arise for example from a surge in electricity on the LV line damaging customer meters or appliances; and
- Reductions to staff productivity from being unable to access systems required to carry out duties as a result of system failure.

As noted above, the requirement to reach MIL 3 arises on the transmission network. However, while our electricity and gas distribution networks are only required to meet MIL 2, we originally allocated the operational costs of meeting MIL 3 across our transmission and distribution networks according to customer numbers, given that IT is a shared service (with any upgrades benefitting the customers of all networks). However, while the AER considered that it is prudent for AusNet Services to increase its cyber security posture, it did not consider that that approach was efficient. In particular, the AER's consultant, EMCa noted that achieving MIL 2 is prudent for AusNet Distribution, while achieving MIL 3 is prudent for AusNet Transmission as follows:

> "Our understanding is that TNSPs are in the 'Highly Critical' group. As AusNet states, there is not currently a regulatory obligation for it to achieve MIL 3 by a specific deadline. However, based on information regarding assessed criticality and escalating cyber threat levels, we acknowledge that AusNet's intention for its Transmission business to enhance its cyber security level towards MIL 3 in the next RCP is likely to represent the actions of a prudent TNSP operator."[81]

Ultimately EMCa agreed that our approach to meeting our forthcoming security requirements was efficient but the proposed allocation of costs between the networks was not. Therefore, in line

[80] *Draft decision – AusNet Services Distribution Determination 2021–26: Attachment 6: Operating expenditure* (September 2020), p57.

[81] EMCa, *AusNet Services - Review of proposed opex ICT-related step changes: Report prepared for: Australian Energy Regulator* (August 2020).

with the AER's Electricity Distribution Draft Decision for AusNet Services, we have allocated the costs of meeting MIL 3 solely to transmission and away from our distribution networks.

The cost increase associated with the cyber security program meets the AER's definition of a forecast opex step change as it is an externally imposed change in the scope or scale of required opex driven by new compliance requirements. The step change is allocated to the IT expenditure category. We have categorised program expenditure as both recurrent and non-recurrent. While this will underpin the security of our network, this program does not result in an increase in the output growth parameters or productivity benefits rather benefit manifest as reduced risk. The costs associated with this regulatory obligation are necessary to comply with clause 6.5.6(a)(2) of the NER, therefore, a do-nothing option was not considered in relation to this step change.

As noted in section 5.5 (Incorporating customer preferences and feedback), we discussed the proposed cyber security step change with customers and stakeholders at a Deep Dive on 30 June 2020. The key observations made by stakeholders were:

- Attendees acknowledged that networks should continue developing cyber security capabilities (even in the face of delays to legislation) but noted there must be a clear narrative explaining how customers will benefit.
- Given this is a highly technical area, attendees noted it is difficult to comment on the reasonableness of the proposed expenditure.
- Stakeholders queried why the provision of a secure system is not part of a business as usual 'duty of care'.

The table below provides our forecast expenditure for the proposed cyber security step change.

Table 5-12: Proposed cyber security step change ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Cyber security step change	**7.5**	**6.4**	**5.0**	**4.7**	**4.2**	**27.9**

Although this program is driven by a regulatory obligation, we have also conducted NPV analysis of the costs and four benefits described above relating to the proposed cyber security program. The results of this analysis are shown in the table below.

Table 5-13: NPV of cyber costs and benefits ($M, real 2021-22)

	Total costs PV	Benefits PV	Net PV
Present Value $	**65.4**	**139.9**	**74.6**

Note: total costs include capex, BAU opex and step change opex.

Source: *ANT - TRR 2023-27 Technology Document ICT Program Brief Cyber Security - 29 Oct 2020*

Full details of the requirements of this project (including the necessary capex and opex), quantification of benefits and recurrent and non-recurrent splits can be found in the ICT cyber security program brief that forms part of our proposal.[82]

5.10.3 5 Minute Settlement rule change

In the NEM, there is currently a mismatch between dispatch and settlement periods. Dispatch prices are calculated every five minutes, while the market is settled on the basis of the time-weighted average of the six five-minute dispatch prices over the 30-minute trading interval.

[82] *ANT - TRR 2023-27 Technology Document ICT Program Brief Cyber Security - 29 Oct 2020.*

The AEMC has amended the Rules to align operational dispatch and financial settlement to occur at five minute intervals.

In order to enable market settlement under these new arrangements, meter data service providers are required to enhance their system capabilities relating to Type 1 and Type 2 meters so that these systems can process and report on five minute interval data. The additional investment undertaken by our meter data service provider, Mondo, to comply with these new requirements will result in AusNet Services incurring higher service charges in the next regulatory period as Mondo recovers a portion of its investment. Mondo will also recover its investment from its non-regulated customers.

This cost increase meets the AER's definition of a forecast opex step change as it is an externally imposed change in the scope or scale of required opex driven by new compliance requirements. The step change is allocated to the IT expenditure category and we have categorised this program as recurrent expenditure, on the basis that it relates to an ongoing compliance requirement with periodic expenditure. This program does not result in an increase in the output growth parameters or deliver productivity benefits to us as it is a compliance-based program. Therefore, customer benefits do not manifest in the network sector; they are enabled in the wholesale electricity market. As a regulatory obligation, this step change is necessary to comply with clause 6.5.6(a)(2) of the NER. As such a do-nothing option was not considered in relation to this step change.

The table below describes our forecast expenditure, which is supported by a quote from our meter data service provider.[83] The expenditure has been updated to account for the AEMC's latest ruling in July 2020 which delayed the rollout of 5 Minute Settlement by three months to 1 October 2021.[84]

Table 5-14: Proposed Five Minute Settlement step change ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Five Minute Settlement step change	**0.9**	**0.9**	**0.9**	**0.6**	**0.6**	**3.9**

Note: numbers may not reconcile due to rounding

5.10.4 Environmental Protection Amendment Act

The amendments made to the *Environment Protection Act 2017* (Vic) by the *Environment Protection Amendment Act 2018* will come into effect on 1 July 2021. The new legislation a proactive regulatory approach focusing on preventing the future adverse environmental impacts due to historic waste and pollution of sites inherited at privatisation. This is a departure from the prior regime, which focused on managing impacts after an adverse environmental event occurred from existing assets and, accordingly, alters the way we must manage our environmental obligations going forward.[85]

To meet the new, proactive compliance obligations, we have forecast opex for annual noise testing to detect noise exceeding acceptable decibel levels and allowable proximity to residential properties, as well as testing pollution levels within soil and groundwater.

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[83] *ANT - TRR 2023-27 Appendix 5C 5-minute Settlement Quote - 29 Oct 2020*.

[84] Australian Energy Market Commission, *Rule Determination: National Electricity Amendment (Delayed Implementation of Five Minute and Global Settlement) Rule 2020* (9 July 2020).

[85] For example, we have an existing obligation to manage oil spills from our assets. We have addressed this obligation through the installation of bunds and water/oil separators at each site. The amended legislation requires us to now assess and manage historic oil contamination that may have occurred on site before privatisation.

Our cost estimate is based on vendor quotes to conduct this surveillance program. It does not include expenditure for rectification issues identified.

This program meets the AER's definition of a forecast opex step change as it is an externally imposed change in the scope or scale of required opex driven by new compliance requirements. The step change is allocated to the network operations expenditure category and we have categorised this program as recurrent expenditure, on the basis that it relates to an ongoing compliance requirement with periodic expenditure. This program does not result in an increase in the output growth parameters or deliver productivity benefits to us as it is a compliance-based program, as recognised in the AER's recent draft decisions for the Victorian electricity distribution networks.[86]

The table below provides our forecast expenditure.

Table 5-15: Proposed Environmental Protection Act step change ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
EPA step change	**0.6**	**0.6**	**0.6**	**0.7**	**0.7**	**3.2**

More information of the requirements of this project and associate cost estimates can be found in ANT - TRR 2023-27 Appendix 5B Standalone EPA Step Change - 29 October 2020.

5.10.5 Cloud migration

Increasingly, IT software is being offered using a cloud-based software-as-a-service delivery model, with vendors increasingly discontinuing existing on-premise solutions. This is driven by factors such as the efficiency and scalability gained by standardising software delivery and hosting across multiple customer bases, and traditional constraints necessitating on-premise solutions disappearing (i.e. interoperability, virtualisation and security). These factors are making on-premise investment an increasingly inefficient and complex delivery model.

Cloud-based systems are opex solutions, distinct from on-premise capex. As our critical applications reach end-of-life or require upgrades, this provides us with opportunities to migrate applications to the cloud at lower cost and to realise cost savings under a capex/opex trade-off. In the upcoming regulatory period we identified opportunities to migrate the following systems to cloud:

- **Corporate Enablement**: continued provision of reliable services to customers by maintaining support and functionality of core enterprise systems (i.e. Finance, HR and Supplier Management) by migrating to a cloud based ERP solution.
- **Corporate Communications**: refreshing our corporate telecommunications infrastructure including increasing our data processing capabilities.
- **Information Managemen**t: enhancing the existing Information Management platform, which integrates data from across the business, to enhance our abilities to analyse data using advanced analytics to enable rapid access to timely, accurate data across all critical systems, assets and processes through a cloud based solution.
- **Workforce Collaboration**: enhance existing processes by developing a fully integrated cloud-based platform to optimise knowledge capture and disseminate knowledge within the organisation, further enhancing the effectiveness of the Information Management system.

This program meets the AER definition of a forecast opex step change as it results in lower capex in the next regulatory period (as compared to procuring an on-premise capex solution or because

[86] See *Draft decision – Jemena Distribution Determination 2021–26: Attachment 6: Operating expenditure* (September 2020), p 69.

there is no capex solution available). This step change has both recurrent and non-recurrent components, more information on which can be found in the associated program briefs. This expenditure is not captured in the output growth, productivity or real price changes. The step change is allocated to the IT expenditure category.

The table below provides our forecast expenditure.

Table 5-16: IT cloud step change ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
IT Cloud step change	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**2.3**

Note: numbers may not reconcile due to rounding

Full details of the requirements of this project (including the necessary capex and opex and recurrent and non-recurrent expenditure) can be found in the associated IT project briefs.[87]

5.10.6 Transmission ring-fencing guideline

In November 2019, the AER commenced a review of the ring-fencing arrangements for transmission network service providers. In particular, the AER is considering how to achieve greater alignment of these arrangements with the ring-fencing arrangements that apply to distribution network service providers. Following a delay to the review due to COVID-19, a draft guideline is scheduled to be published in September 2021. As outlined above, we may introduce a step change in our Revised Revenue Proposal to recover additional costs incurred due to changes to the transmission ring-fencing guideline, once the direction of the AER's review is better understood.

5.10.7 Network support costs

Rapid changes to the generation mix, from traditional to renewable sources, is compromising the system security of Victoria's transmission network. This is also reducing the window of opportunity to undertake planned outage activities and maintain our assets. These windows may reduce to such an extent that AusNet Services cannot adequately maintain its assets unless AEMO, in its capacity as the Victorian transmission planning authority, augments the network.

AEMO has advised AusNet Services that if we take outages outside of the windows approved by AEMO (in its capacity as the system operator), even if doing so would be advantageous from a market impact perspective, then we must procure network support in order to ensure AEMO can maintain system security for the duration of the outage. We are currently conducting a full costing exercise with a network support provider to ascertain the full cost of the associated network support that are likely to be required in the upcoming regulatory control period.

As the expected network support costs remain highly uncertain at the time this proposal is submitted, we have not included this expenditure in our opex forecast at this time. We consider that the network support pass-through mechanism under clause 6A.7.2 of the NER is a more appropriate mechanism for recovering these costs. We are working with the AER to clarify how this pass-through mechanism can be applied in these circumstances and may revisit this issue – including the extent to which adjustments to our expenditure forecasts are needed - in our Revised Revenue Proposal.

[87] See *ANT - TRR 2023-27 Technology Document ICT Program Brief Corporate Enablement - 29 October 2020*; *ANT - TRR 2023-27 Technology Document ICT Program Brief Corporate Communications - 29 October 2020*; *ANT - TRR 2023-27 Technology Document ICT Program Brief Information Management- 29 October 2020*; *ANT - TRR 2023-27 Technology Document ICT Program Brief Workforce Collaboration - 29 October 2020*.

5.11 Total controllable opex

Taking into account the forecast opex outlined above, the annual forecast for total controllable opex is set out in the table below.

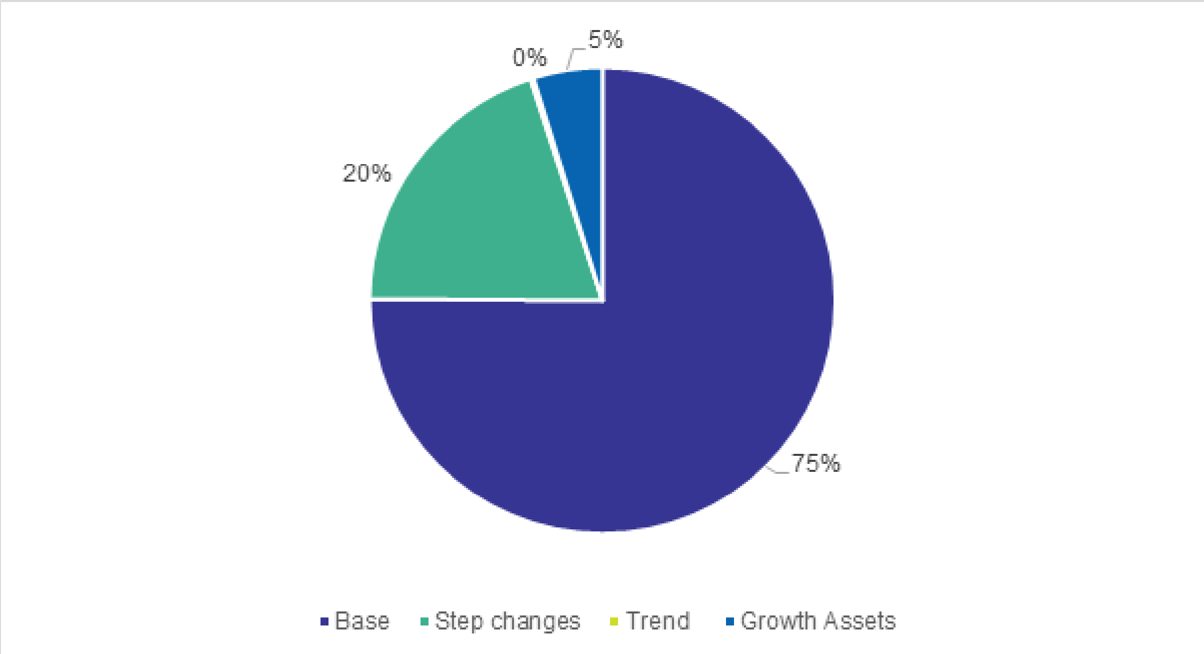
Table 5-17: Total forecast controllable opex ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Base opex	82.1	82.1	82.1	82.1	82.1	**410.1**
Rate of change	0.0	0.0	0.1	0.4	0.7	**1.2**
Growth assets roll in	5.2	5.2	5.2	5.2	5.2	**26.2**
Step changes	23.7	22.6	21.3	20.8	20.3	**108.7**
Total	**110.9**	**109.8**	**108.6**	**108.4**	**108.2**	**546.1**

Note: numbers may not reconcile due to rounding

The different components of forecast controllable opex are shown in the figure below. Efficient base year opex accounts for 75% of the total controllable opex forecast.

Figure 5-6: Components of forecast controllable opex



5.12 Non-controllable opex

Non-controllable opex comprises easement tax and debt raising costs. While these costs are outside AusNet Services' control, they form part of the total operating expenditure the network will incur to meet the operating expenditure objectives set out in clause 6A.6.6. Non-controllable costs are excluded from base year costs.

5.12.1 Easement Land Tax

In 2004, the Victorian Government extended land tax to electricity transmission easements owned by electricity transmission companies in Victoria. The new tax arrangement was designed to counter a shortfall in Government revenue as a result of the abolition of the Smelter Reduction Amount levy.

Easement land tax is recovered through its inclusion in the opex forecasts used in the calculation of the revenue cap for the forthcoming regulatory control period. The forecast assumes that the tax increases at the same rate as CPI over the forthcoming regulatory period.

Over the period, any positive or negative variation between the actual tax paid and the forecast approved by the AER will be recovered from, or reimbursed to, customers via the pass-through mechanism outlined in clause 6A.7.3. This arrangement ensures AusNet Services will only recover the actual tax paid over the period.

Forecast easement land tax over the forecast period is shown in the table below.

Table 5-18: Forecast easement Land Tax ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Easement land tax	**163.2**	**163.2**	**163.2**	**163.2**	**163.2**	**815.9**

Note: numbers may not reconcile due to rounding.

Source: AusNet Services

5.12.2 Debt raising costs

Debt raising costs principally comprise legal fees and banking fees. We propose to forecast debt raising costs by applying 8.50 basis points per annum to the debt raised, in accordance with the AER's recent determination for SA Power Networks.

Table 5-19: Forecast debt raising costs ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Debt raising costs	**1.7**	**1.7**	**1.7**	**1.8**	**1.7**	**8.7**

Note: numbers may not reconcile due to rounding.

5.13 Why our opex forecasts satisfy the Rules requirements

As explained in this Chapter, we consider that the total opex forecast for the forthcoming regulatory period complies with the Rules requirements because the forecast reasonably reflects each of the operating expenditure criteria, being:

- The efficient costs of achieving the operating expenditure objectives (which are set out in NER 6A.6.6(a));
- The costs that a prudent operator would require to achieve the operating expenditure objectives; and
- A realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

As such, the AER's obligation to make decisions that are consistent with the achievement of the NEO as they pertain to a prudent transmission network service provider are satisfied by its acceptance of the opex forecasts presented in this chapter.

In addition, as noted in section 5.4 above, cost inputs used to develop the opex forecast have been allocated in accordance with AusNet Services' approved Transmission CAM. These forecasts have also been developed at arms length to other entities.

In satisfaction of NER S6A.1.2(7), which requires a Revenue Proposal to contain actual opex for the first three regulatory years of the current regulatory control period, and expected opex for the last two regulatory years of that regulatory control period categorised in the same way as the opex forecast, we have provided the following table.

Table 5-20: Average annual forecast controllable opex ($M, real 2021-22)

	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	Service Category
Controllable opex	88.3	87.3	86.8	81.5	86.2	112.7	111.6	110.4	110.2	110.0	All categories*
Rebates under the Availability Incentive Scheme	0.1	0.2	0.3								Shared network services
Easement Land tax	145.5	143.2	176.1	163.1	163.2	163.2	163.2	163.2	163.2	163.2	Shared network services
Merits review opex	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	All categories*
Movements in provisions	-2.1	4.7	-5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	All categories*
Total	**231.9**	**235.5**	**258.2**	**245.5**	**249.4**	**275.9**	**274.8**	**273.5**	**273.4**	**273.1**	

* Service categories involve three categories, entry services, exit services, and shared network services.

Note: movements in provisions are not forecast. Where available actuals have been used for the current period, 2020-21 and 2021-22 are forecasts based on the approved budget.

5.14 Supporting documents

We have included the following documents to support this chapter:

- Appendix 5A – Growth Assets
- Appendix 5B – Standalone EPA Step Change
- Appendix 5C – 5-minute Settlement Quote
- Appendix 5D - BIS Oxford Economics Labour Price Forecasts

A significant number of other documents, including the Opex Model and supporting step change documents, support our operating expenditure proposal.

6 Shared assets

6.1 Key points

This Chapter sets out AusNet Services' proposed shared assets and the subsequent cost reductions for the 2023-27 regulatory control period. A shared asset is an asset whose costs were initially allocated to prescribed transmission services but has come to be used to provide non-regulated transmission services and/or services that are not transmission services. The change in expected use means the assets are earning both regulated and unregulated revenues. By definition, assets used to provide both prescribed and negotiated transmission services, or market network services, are excluded from the shared assets mechanism.

Under clause 6A.5.5 of the Rules, the annual revenue requirement may be reduced to reflect that part of the costs of the asset that is attributable to providing both prescribed transmission services and unregulated services.

The cost reduction must be made in accordance with the shared asset principles (NER 6A5.5(c)), which are:

- The service provider should be encouraged to use assets to provide unregulated services where efficient.
- The cost reduction should not be dependent on the service provider deriving a positive commercial outcome for unregulated services provided using the shared asset.
- The cost reduction should be applied where there is material use of the asset to provide unregulated services.
- Regard should be had to how costs have been recovered or revenues reduced in the past with respect to the shared asset.
- The cost reduction must be compatible with the Cost Allocation Principles and the Cost Allocation Methodology.
- Any cost reduction must be compatible with other incentives provided by the Rules.

The AER's Shared Asset Guideline outlines its proposed approach to making shared asset cost reductions, which is summarised below.

6.2 Cost reduction methodology

The AER's Shared Asset Guideline sets out the following steps to establish the shared asset cost reduction:

- Determine the relevant unregulated revenues earned from shared assets;
- Determine whether the shared asset unregulated revenues (SAUR) are material (i.e. the revenues exceed 1% of the proposed annual revenue requirement).
- Where the SAUR is material, apply a revenue reduction equal to 10% of the total unregulated revenues from shared assets for each year of the regulatory control period, subject to:
    - The application of the control step (i.e. cap); and/or
    - Any adjustments made to account for contributed assets.

The Shared Asset Guideline notes that service providers may propose alternative methods to calculate a cost reduction, providing that customers would be no worse off compared to the method in the Guideline.

AusNet Services has applied the Guideline methodology and the steps we have taken are set out below.

6.2.1 Relevant unregulated revenues from shared assets

Our forecast for relevant unregulated revenues from shared assets is set out in the table below. Revenues associated with these services since 2012-13 have also been reported in the reset Regulatory Information Notice (RIN) template 7.4.

Table 6-1: Forecast Shared Asset Unregulated Revenues (SAUR) ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
HV CT & VT Testing	1.1	1.2	1.3	1.4	1.5	**6.7**
Transformer Testing (incl Condition Monitoring)	0.8	0.9	1.0	1.1	1.1	**5.0**
Chemical Testing & Analysis	2.5	2.9	3.3	3.8	4.3	**16.8**
Calibration & Electrical Testing (incl NATA accredited)	1.2	1.2	1.2	1.2	1.2	**5.8**
Fibre Optic Cable Leasing	2.7	3.4	4.1	5.1	6.3	**21.6**
Leasing Access to wireless base stations on EHV Towers	6.4	6.7	7.0	7.4	7.7	**35.2**
Leasing Access to various communication equipment on communication towers	2.4	2.7	3.1	3.5	3.9	**15.7**
Site Leasing	0.4	0.4	0.4	0.4	0.4	**1.9**
TOTAL	**17.6**	**19.4**	**21.4**	**23.8**	**26.5**	**108.6**

6.2.2 Materiality test

The Shared Asset Guideline specifies that the unregulated use of shared assets is material when the average annual unregulated revenues from shared assets is expected to be greater than 1% of the total smoothed revenue requirement for that regulatory year.

Our unregulated use of shared assets is expected to be material in all years of the forthcoming regulatory control period. The results of the materiality assessment are shown in the table below.

Table 6-2: Materiality Assessment Outcome ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Proposed smoothed ARR	556.5	542.5	528.9	515.6	502.6	**2646.1**
Average Annual SAUR	21.7	21.7	21.7	21.7	21.7	**108.6**
SAUR as % of ARR	3.9%	4.0%	4.1%	4.2%	4.3%	**4.1%**
Material? (Y/N)	Y	Y	Y	Y	Y	**N/A**

6.2.3 Shared asset cost reduction

The Shared Asset Guideline states that the AER will consider evidence of consumers benefitting from assets upgraded or replaced by third parties when determining shared asset cost reductions. We propose that our shared asset revenue decrement should be adjusted to recognise the benefits to customers of the following assets that have been contributed by third parties:

- **Transmission line realignment project –** In September 2019, a third party contributed **3079** conductors and **6** towers as part of a line realignment project. The benefit to our transmission customers is that the third party contribution deferred the cost of replacing these assets by approximately 10 years. This benefit will be realised approximately 40 years in the future for the poles and 50 years for the conductors and towers. The future benefit of deferred replacement has been discounted by our proposed WACC to estimate the benefit today. The total benefits have been averaged evenly across all years of the period.

The estimated customer benefits associated with the contribution of these assets are shown in the table below. For the purposes of calculating the shared asset cost reduction, AusNet Services proposes allowing consumers to share in the benefits from contributed assets by adjusting its proposed shared asset revenue decrement by 50% of the estimated benefit to customers.

Table 6-3: Consumer benefits from Contributed assets ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Transmission project	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	**(1.1)**

Consistent with the Guideline, the shared asset cost reduction has been calculated as 10% of the value of expected total relevant unregulated revenues from shared assets in that year.

The proposed shared asset cost reduction for the 2023-27 regulatory control period is set out in the table below.

Table 6-4: Shared Asset Cost Reduction ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
10% of relevant unregulated shared asset revenues	1.8	1.9	2.1	2.4	2.6	**10.9**
Less 50% of consumer benefits from contributed assets	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	**(0.5)**
Shared asset cost reduction	**1.7**	**1.8**	**2.0**	**2.3**	**2.5**	**10.3**

6.3 Summary

The impact of the shared assets cost adjustment on AusNet Services' proposed smoothed Annual Revenue Requirement is shown in the table below.

Table 6-5: Decrement from Shared Assets ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
ARR	556.5	542.5	528.9	515.6	502.6	**2646.1**
Shared asset cost reduction	(1.7)	(1.8)	(2.0)	(2.3)	(2.5)	**(10.3)**
Adjusted ARR	554.8	540.7	526.9	513.3	500.1	**2,635.8**

7 Incentive schemes

7.1 Key points

The key points of this chapter are:

- AusNet Services' performance under the current period's various incentive schemes demonstrates incentive regulation continues to be effective. We have a strong record of delivering lower operating costs and improved service levels in response to the incentive framework.
- Consistent with recent AER determinations, proposed Service Component parameter targets have been set on the basis of average historic performance, with caps and collars set at the 5th and 95th percentiles of historic performance using the most appropriate statistical distribution. However, due to our strong performance in the current period, if we record 0 events in 2020 for the number of loss of supply events greater than 0.30 system minutes sub-parameter, this would result in a target (and by extension a cap and collar) of zero, and we hold concerns that a 0 target would be an inappropriate application of bonus-penalty incentives.
- The number of constrained dispatch intervals as measured under the Market Impact Component of the STPIS has increased markedly, with the 2019 result representing the highest number of constrained dispatch intervals caused by outages on the Victorian transmission network since measurement began, as a result of significant transformation in the wholesale energy market. Due to these energy system changes, we consider that an urgent review is warranted of the current service target performance incentive arrangements applying to transmission networks, in particular the Market Impact Component, to ensure they remain fit for purpose.
- The Network Capability Incentive Parameter Action Plan allows for a range of priority projects to improve network capability, noting that the three projects successfully delivered to date have created positive net benefits of $7.2 million.
- The Efficiency Benefit Sharing Scheme and Capital Expenditure Sharing Scheme carryover amounts have been calculated as $38.1 million and $6.4 million, respectively, reflecting our response in recent years to the cost efficiency incentives embedded in the regime.

7.2 Chapter structure

This chapter sets out AusNet Services' proposed approach to the incentive schemes that will be applied during the forthcoming 2023-27 regulatory control period: These schemes are the:

- Service Target Performance Incentive Scheme (STPIS);
- Efficiency Benefit Sharing Scheme (EBSS); and
- Capital Efficiency Sharing Scheme (CESS).

The Demand Management Innovation Allowance (DMIA) is a new incentive scheme for TNSPs designed to promote innovation in non-network solutions, which the AER is currently developing. We consider this scheme should be applied to us during the forthcoming regulatory control period.

Our performance against these schemes during the current regulatory control period is also presented.

This chapter is structured as follows:

- Section 7.3 presents our historical performance under the STPIS, and sets out our proposed targets, caps and collars for the forthcoming regulatory control period;

- Section 7.4 provides the calculation of the EBSS carryover amount from the current regulatory control period, and sets out our proposed application of the EBSS for the forthcoming regulatory control period; and
- Section 7.5 discusses the application of the CESS for the forthcoming regulatory control period.

7.3 Service Target Performance Incentive Scheme

The STPIS provides a financial incentive to maintain and improve service performance for the benefit of consumers. The scheme encourages us to deliver a reliable electricity supply, as well as maximise the availability of our network to serve the lowest-cost generators. The STPIS, therefore, plays an important role in counter-balancing the incentives to minimise operating (EBSS) and capital expenditure (CESS) that are provided by other aspects of the regulatory framework.

Version 5 of the STPIS will apply to AusNet Services during the 2023-27 regulatory control period. This comprises the following three components:

- The service component (SC);
- The market impact component (MIC); and
- The network capability component (NCC).

The SC provides incentives to reduce the occurrence of unplanned outages and to return the network to service promptly should these unplanned outages occur. By encouraging TNSPs to focus on reducing unplanned outages, this component also incentivises us to identify and address potential network reliability issues. Performance targets for the SC are established for the following parameters:

- Unplanned outage circuit rate;
- Loss of supply event frequency;
- Average outage duration; and
- Proper operation of equipment.

Financial incentives apply only to the first three parameters and their various sub-parameters. Performance under the ‘proper operation of equipment’ parameter is only used for reporting purposes and has no financial incentives attached.

The MIC provides an incentive to minimise the impact of transmission outages at times and on parts of the network that are most important to influencing the spot price in the wholesale market. Performance is measured based on the number of five-minute dispatch intervals (DIs) constrained when an outage constraint binds with a marginal value greater than $10/MWh.

However, in recent years, AEMO has modified its approach to managing system security in response to the significant changes in the wholesale energy market, most notably the closure of thermal generation (e.g. Hazelwood Power Station) and the dramatic increase in renewable generation (particularly in North-Western Victoria). The MIC has not been adapted to keep pace with these specific changes to the Victorian transmission network.

In light of these significant developments, in February 2020 Energy Networks Australia formally requested the AER to review the MIC to ensure it remains fit for purpose given the external challenges in the current operating environment. On 18 August 2020 the AER formally responded to our request to inform us that it saw no immediate need to review the MIC, but a STPIS review is likely to occur in the near future to incorporate NEM changes arising from COGATI, the AEMC’s review into system strength , the ESB’s post-2025 Market Design work and as part of the AER’s forthcoming review into the operation and effectiveness of incentive schemes.

We continue to strongly support a thorough review into this component to ensure it provides appropriate incentives during the forthcoming regulatory control period. Due to the split in Victorian transmission planning responsibilities we have fewer available options and less flexibility to manage outages compared to other TNSPs. We are working with the AER on ways to increase our ability to respond to the scheme while maintaining an incentive to manage outages in a way which will lower whole-of-supply chain costs to customers. This includes the ability to recover costs associated with efficient network support contracts.

The NCC provides incentives to deliver low cost, one-off projects that both increase network capability when it is most needed and also provides value for money to customers. Each TNSP is required to submit, as part of its Revenue Proposal, a Network Capability Incentive Parameter Action Plan (NCIPAP). The TNSP must also consult the Australian Energy Market Operator (AEMO) in developing the NCIPAP. In Victoria, the involvement of AEMO is more substantial. As the planner of the Victorian transmission network, it is responsible for identifying and scoping projects and working with us to quantify project benefits.

In accordance with the scheme, the remainder of this section sets out:

- Our performance against the STPIS during the 2017-22 regulatory control period measured in accordance with Version 5;
- Proposed metrics for the SC parameters;
- Proposed metrics for the MIC performance target, the unplanned outage event limit and dollar per dispatch interval incentive rate, if the MIC is to be applied to AusNet Services; and
- Our NCIPAP proposal.

Current period performance

7.3.1.1 Service Component

The SC provides strong incentives for TNSPs to improve network reliability. Our performance against each individual SC parameter is shown in the table below.

Table 7-1: Historical Service Component performance

Parameter	Sub-parameter	2015	2016	2017	2018	2019	2015-19 average
Unplanned outage circuit event rate	Lines event rate – fault	19.01%	14.88%	21.95%	18.03%	13.01%	**17.38%**
	Transformer event rate - fault	14.29%	10.40%	12.60%	14.96%	6.25%	**11.70%**
	Reactive plant event rate - fault	18.57%	18.84%	15.49%	16.90%	29.58%	**19.88%**
	Lines event rate - forced	15.70%	17.36%	5.69%	15.57%	4.88%	**11.84%**
	Transformer event rate - forced	11.11%	12.80%	15.75%	7.87%	11.72%	**11.85%**
	Reactive plant event rate - forced	34.29%	30.43%	29.58%	33.80%	25.35%	**30.69%**
	Number of events greater than 0.05	2	3	0	0	1	**1.2**

Parameter	Sub-parameter	2015	2016	2017	2018	2019	2015-19 average
Loss of supply event frequency	system minutes per annum						
	Number of events greater than 0.30 system minutes per annum	1	1	0	0	1	**0.6**
Average outage duration	Average outage duration	97.5	39.8	19.0	24.5	87.0	**53.6**
Proper operation of equipment	Failure of protection system	30	23	46	28	33	**32**
	Material failure of SCADA	0	2	0	0	2	**0.8**
	Incorrect operational isolation of primary or secondary equipment	5	6	12	7	1	**6.2**

Source: AusNet Services

7.3.1.1.1 Unplanned outage circuit event rate

The figures below show our performance since 2015 for the six unplanned outage circuit rate sub-parameters, as well as the targets, caps, and collars. The charts demonstrate that we have made significant service performance improvements during the last five years for most parameters.

The unplanned outage circuit rate parameter measures outage rates for lines, transformer, and reactive plant assets for both forced and fault outages. In order to minimise the impact on our customers, we rapidly respond to and restore fault outages on our network.

Since 2015, we have consistently outperformed our targets for each of the lines, transformers, and reactive plant fault outage rates.

We have also performed well for forced outages for line assets, while our transformers and reactive plant forced outages have been reasonably consistent within the last 5 years when compared to our targets. We will continue to work to improve performance against all three forced outage rate sub-parameters as the current regulatory control period progresses.

Figure 7-1: Unplanned outage circuit event rate – lines (fault outages)

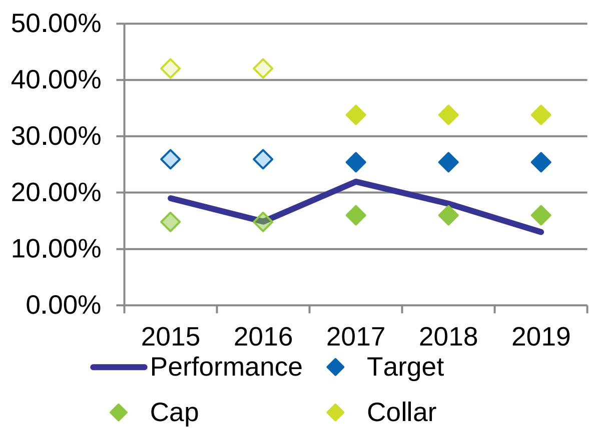


Figure 7-2: Unplanned outage circuit event rate – lines (forced outages)

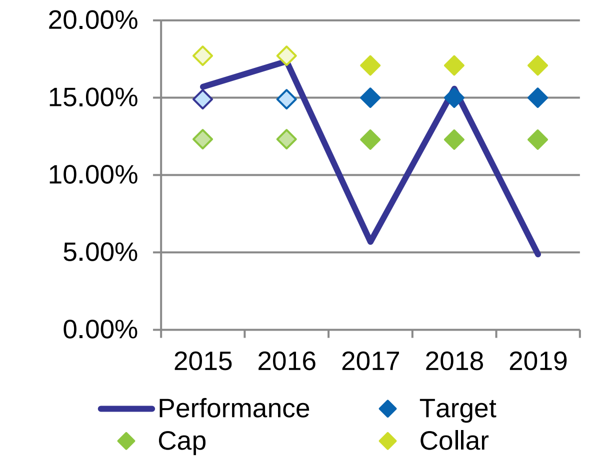


Figure 7-3: Unplanned outage circuit event rate – transformers (fault outages)

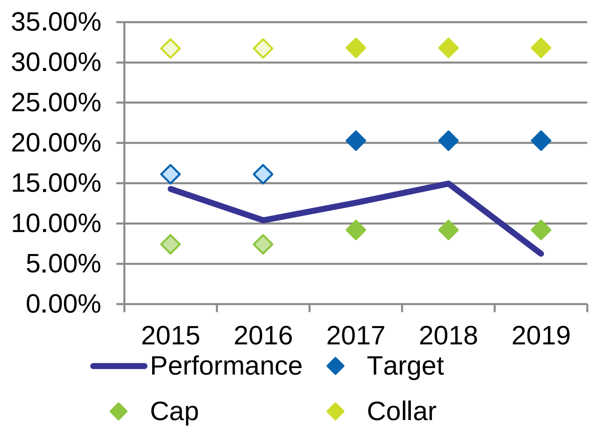


Figure 7-4: Unplanned outage circuit event rate – transformers (forced outages)

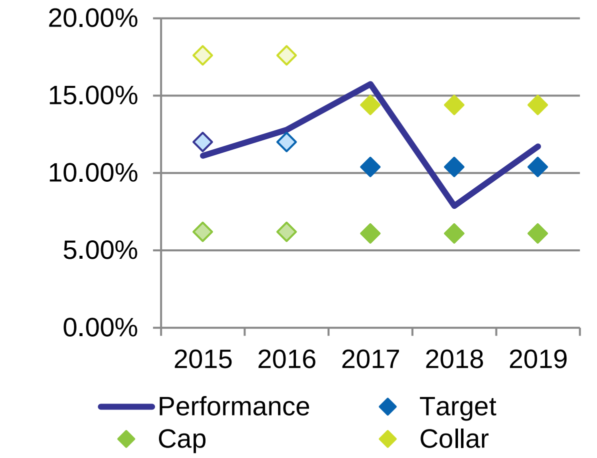


Figure 7-5: Unplanned outage circuit event rate – reactive plant (fault outages)

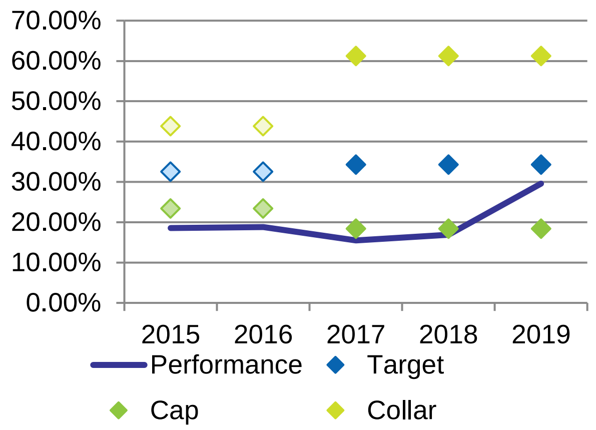
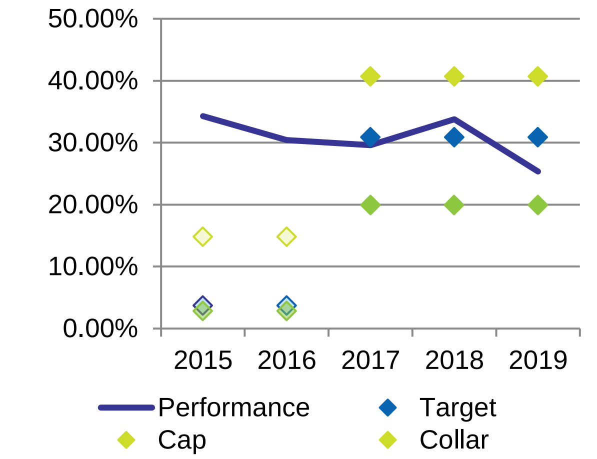


Figure 7-6: Unplanned outage circuit event rate – reactive plant (forced outages)



7.3.1.1.2 Loss of Supply Event Frequency Rate

This parameter measures the frequency of loss of supply events exceeding thresholds of 0.30 and 0.05 system minutes. Loss of supply events are caused by unplanned outages and only a small number of events are likely to occur each year. As a result, performance against this parameter has the potential to be relatively volatile year to year.

The figures below show our performance since 2015 for both parameters.

Figure 7-7: Loss of Supply Event Frequency (>0.05 system minutes)

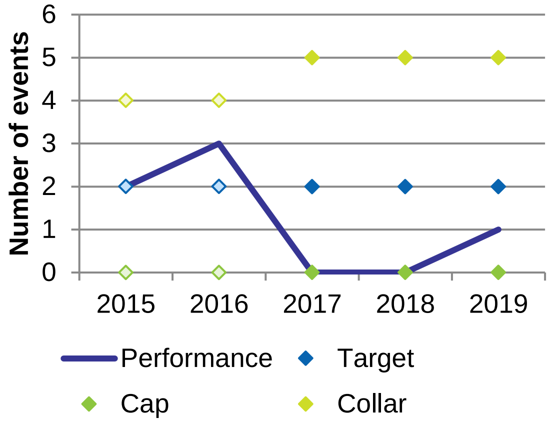
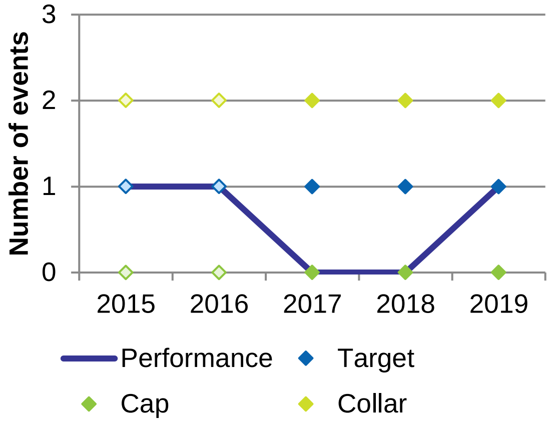
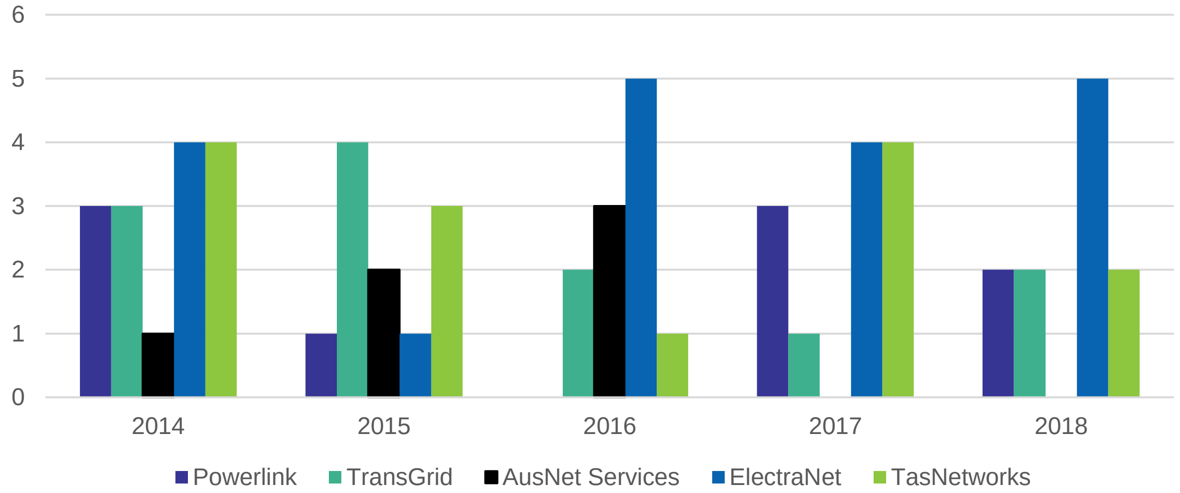


Figure 7-8: Loss of Supply Event Frequency (>0.30 system minutes)



Since 2015, with the exception of 2016, we have either met or outperformed the AER's target for loss of supply events, as measured by the scheme. For 2017 and 2018, we had no loss of supply events – a performance which is an exceptional outcome for customers. This highlights the reliability of the Victorian transmission network. As the figure below illustrates, we compare favourably with our peers for our strong performance in this parameter.

Figure 7-9: Reliability comparison with other TNSPs (no. of loss of supply events >x system minutes)



Source: *Economic Benchmarking RIN Responses 2014, 2015, 2016, 2017, 2018*

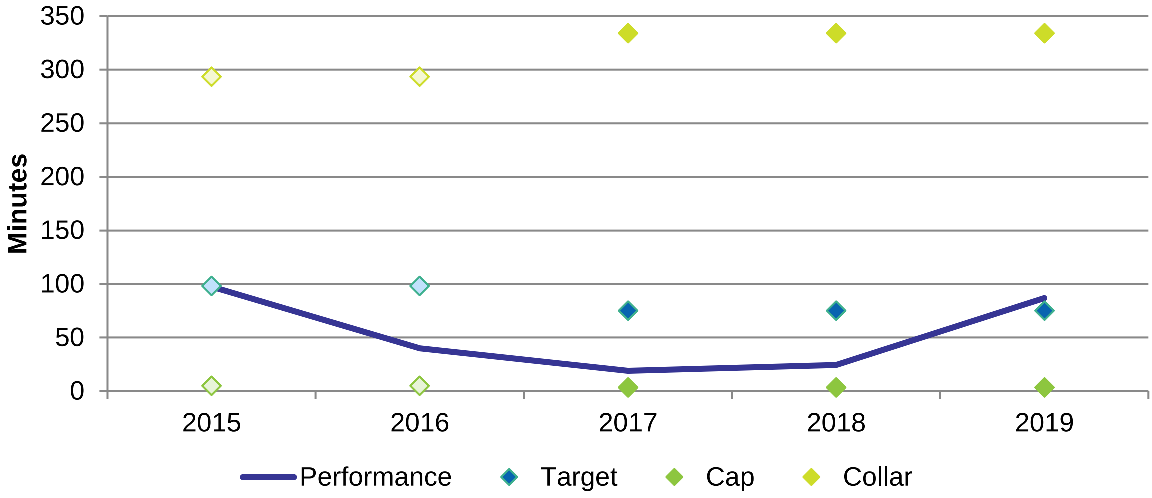
While we continue to look for ways to avoid and minimise outages and loss of supply to customers, this has resulted in us approaching the performance frontier for this parameter, with further improvement beyond this point increasingly difficult.

7.3.1.1.3 Average outage duration

The average outage duration parameter measures our ability to restore service following an unplanned outage in a timely manner. Performance against this parameter can be severely affected by a small number of particularly long outages, for example outages on assets such as transformers, which can take several weeks to restore.

The figure below shows our historical performance for this parameter since 2015.

Figure 7-10: Average outage duration (minutes)



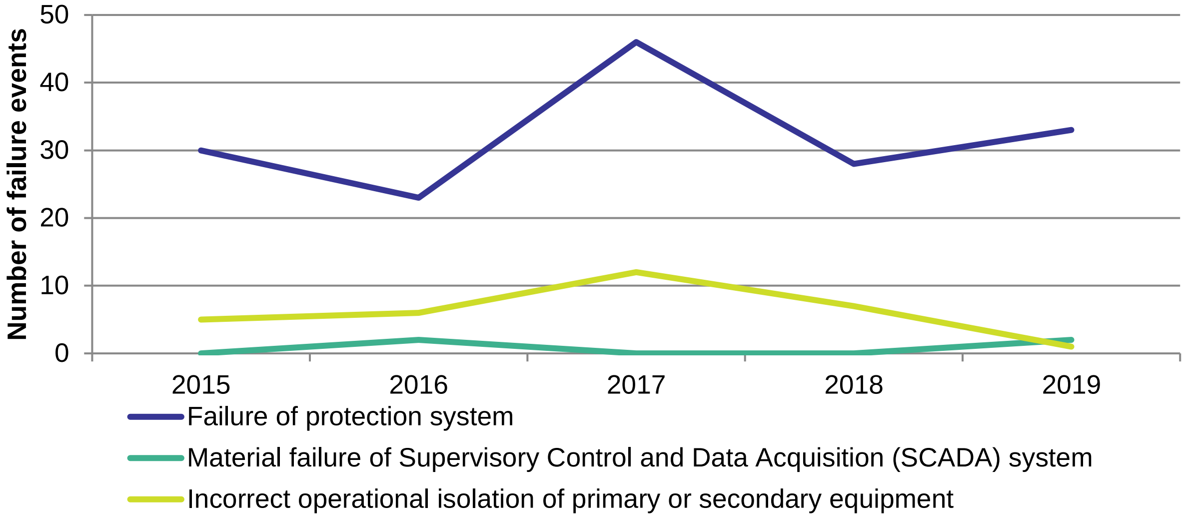
Overall, our performance against the average outage duration parameter has been strong, outperforming the target measure from 2016.

7.3.1.1.4 Proper operation of equipment

The proper operation of equipment parameter measures the number of ‘near miss’ events such as failures of protection systems, material failure of the Supervisory Control and Data Acquisition (SCADA) system and incorrect operational isolation of primary and secondary equipment. As aforementioned, no financial incentive is associated with this parameter and so our performance is only used for reporting purposes.

The figure below shows the number of events that have occurred since 2015 for each sub-parameter.

Figure 7-11: Proper Operation of Equipment (number of failure events)

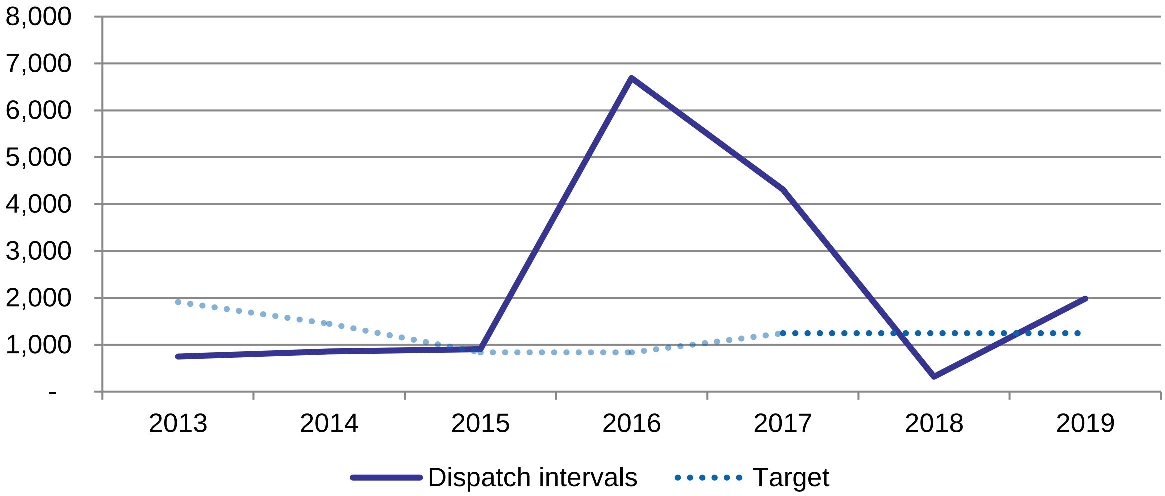


Since 2015, the number of material SCADA system failure and incorrect operational isolation of equipment events has remained largely steady. However, the number of protection system failure events increased substantially in 2017, before steadying in 2018. The 2017 performance year experienced a number of different events which reoccurred multiple times. We note that due to the highly volatile nature of the Proper Operation of Equipment sub-parameters, significant variation between year-on-year performance is to be expected.

7.3.1.2 Market Impact Component

The MIC provides strong incentives for TNSPs to minimise the impact of transmission outages that affect wholesale market outcomes. The figure below shows annual performance data for the calendar years since 2015 under STPIS Version 5.

Figure 7-12: Market Impact Component – number of constrained dispatch intervals with a marginal value greater than $10/MWh



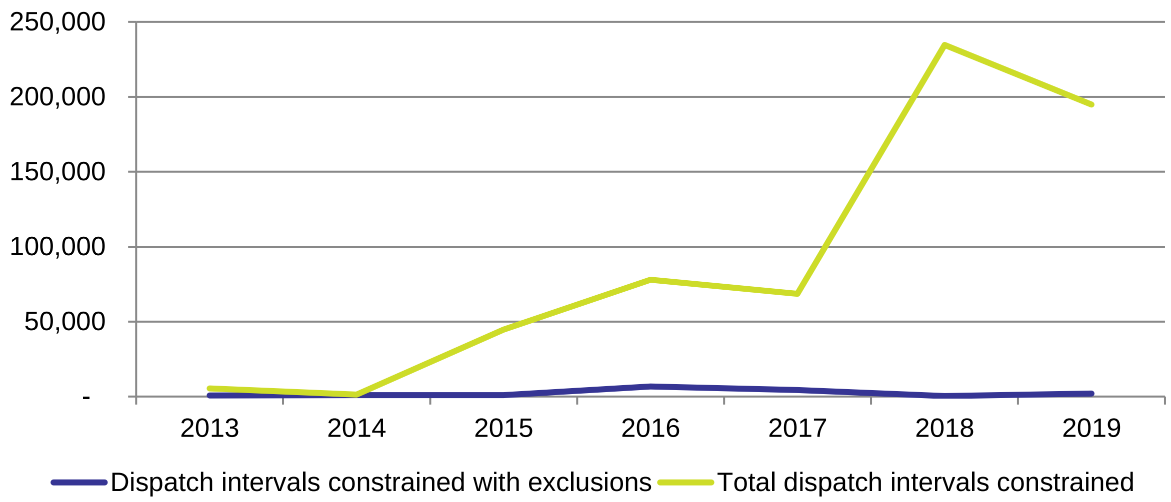
Our performance in the current regulatory control period may suggest we are performing broadly in line with targets; however, we do note that it has become increasingly more challenging to manage the market impact of transmission congestion in recent years. Performance against the MIC is highly dependent on the frequency and duration of critical maintenance activities undertaken during each assessment period (measured on a calendar year basis). Although our enhanced outage planning activities have mitigated the market impact of these activities, the increase in the incidence of excluded market impact dispatch intervals (being intervals when we cannot take an outage) has been unavoidable. This increase in dispatch intervals is reflective of several broad changes occurring within the Victorian energy system:

- Strong investor interest in western parts of the state is shifting the geographic footprint of supply sources away from the Latrobe Valley, while increasing penetration of non-synchronous generation is further changing the technical characteristics of the system.
- Solar photovoltaic (PV) and other distributed energy resources (DER) technologies are having a significant impact on the Victorian transmission network, with minimum demand occurring in the early afternoon rather than overnight for the first time in 2018/19. Additionally, parts of the network that have historically been net loads are now behaving increasingly as net generation sources – changing system dynamics at a fundamental level.
- The network challenges associated with integrating large volumes of new renewable generation projects are being compounded by connection of these new projects in weaker parts of the network, where the highest quality renewable fuel sources are available. These network locations were not originally designed to handle high volumes of generation, or to withstand the technical characteristics associated with renewable generation technology.

These changes are creating significant challenges for AusNet Services' transmission operations. Specifically, there are many system security issues arising due to the changing generation mix and, in order to manage these issues, AEMO has either introduced new or modified existing constraints. These changes materially increase the likelihood of constraints binding and mean that it is increasingly difficult to plan our outages in a window of opportunity where no constraint will bind, as the MIC scheme encourages.

Continuing the existing trend shown in the figure below, we expect this issue to worsen during the forthcoming regulatory control period, unless there are material changes to the operation of the MIC. The significant increase in the number of dispatch intervals that have been excluded since 2013 is demonstrative of the operating challenges the network is facing, and which the MIC has failed to keep pace with. As the figure shows, more than 98% of constrained dispatch intervals are now being excluded to keep the scheme workable.

Figure 7-13: Dispatch intervals constrained with and without exclusions



The step change in the number of exclusions required also greatly increases the complexity of the annual review process, necessitating additional resources from both us and the AER each year.

Given the interpretation of exclusions is now a critical input to determine performance under the MIC, we seek certainty from the AER as to how various exclusions will be interpreted and applied during the next regulatory control period in section 7.3.2.2 below.

7.3.1.3 Network Capability Component

We have taken significant steps to implement the priority projects set out in our NCIPAP. To date, 3 of the 7 priority projects contained in the endorsed NCIPAP for the 2017-22 regulatory control period have been completed. The target limits have been achieved for all completed projects, creating net benefits of around $7.2 million for customers. Once all projects have been completed by the end of the current regulatory control period, we expect to have delivered a total of at least $20.2 million in net customer benefits.[88]

Proposed application of the STPIS

This section sets out our proposed parameter values for the STPIS and explains how the proposed values comply with Version 5 of the scheme. We have always been strongly committed to achieving high operational performance, including at times when we are implementing maintenance programs.

The key features of our STPIS proposal are:

- SC parameter targets are set equal to average historic performance and the caps and collars are set at the 5th and 95th percentiles of historic performance using statistical distributions that best fit this performance data; and
- MIC performance data from 2013-19 is included to enable calculation of an appropriate target for the 2023-27 regulatory control period.

7.3.1.4 Service Component

Methodology for setting targets

Our proposed performance targets, caps, collars, and weightings for the parameters, in accordance with Version 5 of the STPIS, are set out in the table below. In calculating the proposed performance targets for these parameters, we have complied with the requirements of clause 3.2 of Version 5 of the STPIS.

Clause 3.2(g) of the STPIS specifies that, subject to some exceptions, proposed performance targets must be equal to the TNSP's average performance history over the most recent five years. To satisfy this requirement, our proposed performance targets equal the average performance history over the most recent five years (2015-19). We also note that the data used to calculate the performance target must be consistently recorded based on the parameter definitions that apply to the TNSP under the scheme.

Table 7-2: Proposed Service Component targets

Parameter	Sub-parameter	2015	2016	2017	2018	2019	Proposed Target	Weight (MAR %)
Unplanned outage circuit event rate	Lines event rate - fault	19.01 %	14.88 %	21.95 %	18.03 %	13.01 %	*17.38%*	**0.20**
	Transformer event rate - fault	14.29 %	10.40 %	12.60 %	14.96 %	6.25 %	*11.70%*	**0.20**

[88] Customer benefits based on AEMO assessments previously supplied to the AER as part of the annual compliance process.

Parameter	Sub-parameter	2015	2016	2017	2018	2019	Proposed Target	Weight (MAR %)
	Reactive plant event rate - fault	18.57 %	18.84 %	15.49 %	16.90 %	29.58 %	*19.88%*	**0.10**
	Lines event rate - forced	15.70 %	17.36 %	5.69 %	15.57 %	4.88 %	*11.84%*	**0.10**
	Transformer event rate - forced	11.11 %	12.80 %	15.75 %	7.87 %	11.72 %	*11.85%*	**0.10**
	Reactive plant event rate - forced	34.29 %	30.43 %	29.58 %	33.80 %	25.35 %	*30.69%*	**0.05**
Loss of supply event frequency	Number of events greater than 0.05 system minutes per annum	2	3	0	0	1	*1*	**0.15**
	Number of events greater than 0.30 system minutes per annum	1	1	0	0	1	*1*	**0.15**
Average outage duration	Average outage duration	97.5	39.8	19.0	24.5	87.0	*53.6*	**0.20**
Proper operation of equipment	Failure of protection system	30	23	46	28	33	*32*	**0.00**
	Material failure of SCADA	0	2	0	0	2	*1*	**0.00**
	Incorrect operational isolation of primary or secondary equipment	5	6	12	7	1	*6*	**0.00**

The proposed targets have been calculated as discussed below. The targets, caps and collars are then summarised in the next section.

7.3.1.4.1 Unplanned outage circuit event rate

Actual performance for the average Circuit Outage Rate parameter is measured on a two-calendar year rolling average in accordance with Appendix E of the STPIS. The proposed targets are equal to average annual performance for the years 2015 to 2019.

7.3.1.4.2 Loss of supply event frequency

Proposed targets for each Loss of supply event frequency sub-parameter in the forthcoming regulatory control period have been calculated using the following methodology:

1. Calculate average annual performance from 2015-19;[89] and
2. Round the adjusted average performance data to the closest integer, consistent with clause 3.2 (l) of the STPIS.

As demonstrated in section 7.3.1.1.2, our performance under the Loss of Supply Event Frequency parameter has been consistently strong from 2015-19 as we have actively worked to minimise of loss of supply events on our network. This has resulted in outperformance of the target for both moderate and large event thresholds, with further improvements beyond this level increasingly difficult to make. In addition, the proposed target for the period will be updated during the review process to reflect the average annual performance from 2016-20.

Over time, maintained improvements in performance would eventually bring us to the frontier of efficient service performance. As a consequence, if we were to continue our strong performance and record 0 events in 2020 for the number of loss of supply events greater than 0.30 system minutes sub-parameter, this would result in a target (and by extension a cap and collar) of zero for the next regulatory period. While these parameters may reflect the strict operation of the STPIS, we hold concerns that this would be an inappropriate application of bonus-penalty incentives. One of the principles for the design of the STPIS is that it should provide incentives to maintain and improve the reliability of transmission network elements. We consider that a target of zero events is inappropriate and would not achieve this principle. We initially raised this issue with the AER in our 2014-17 Revenue Proposal,[90] when we encouraged the AER to investigate this parameter more closely for TNSPs approaching the performance frontier, and again in our 2017-22 Revenue Proposal.[91]

According to the STPIS definitions, the performance target is defined as "the level of performance that results in a TNSP neither receiving a financial penalty nor financial reward in the regulatory year."[92] This implies that if we achieved 0 events in a particular year (if the target were set as zero), we would not receive any bonus nor penalty because the performance measure equals the performance target. However, the scheme also defines the cap as the level of performance that results in a TNSP receiving the maximum financial reward attributed to a parameter. As aforementioned, a target of zero would imply a cap of zero and, therefore, that TNSPs would receive a bonus should actual performance be 0. Given the principle set out above – i.e. that the STPIS should provide incentives to maintain and improve the reliability of transmission network elements, the latter interpretation should be applied. Otherwise the application of this component over the regulatory period would result in TNSPs receiving a penalty if a single loss of supply event occurred but would not have any opportunity to receive a bonus, even if zero events occurred each year. This degree of asymmetry in an incentive scheme is highly inappropriate – particularly as it is a consequence of TNSPs achieving desirably high levels of performance which cannot be improved upon.

Should there be no loss of supply events greater than 0.30 system minutes in 2020, we will also consider proposing alternative calculation methods in accordance with clause 3.1 (subclause (g), (i) and (j)) in the Revised Revenue Proposal. This will determine an alternative target that we consider will better reflect the intent and design principles of the scheme than would a target of 0 events.

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[89] The AER's Final Decision for the 2023-27 regulatory control period will consider performance data from 2016-20.

[90] *SP AusNet 2014-17 revenue proposal*, February 2013, p. 153-156.

[91] AusNet Services, *Transmission Revenue Review 2017-2022*, October 2015, p. 161-164.

[92] AER, *Service target performance incentive scheme version 5*, October 2015, p. 24.

7.3.1.4.3 Average outage duration

Actual performance for the average outage duration parameter is measured on a two-calendar year rolling average in accordance with Appendix E of the STPIS. The proposed target is equal to average annual performance for the years 2015 to 2019.

7.3.1.4.4 Proper operation of equipment

We have reliable historic data on the number of events that have occurred for each of the three sub-parameters. Accordingly, targets based on 2015-19 performance are proposed to apply to these sub-parameters in the forthcoming period.

Methodology for setting caps and collars

Clause 3.2(e) of the STPIS specifies that the proposed caps and collars must be calculated by reference to the proposed performance targets and using a sound methodology. These may result in symmetric or asymmetric incentives for the TNSP.

The proposed collars and caps have been developed using the same methodology as that adopted by the AER in our current determination and in recent determinations for ElectraNet, TransGrid and TasNetworks. For asymmetrical distributions, this outcome is achieved by setting collars and caps at the 5th and 95th percentile. These percentiles have been calculated using the distribution which best fits the 2015-19 performance data, as determined by statistical analysis using the @RISK software.

The table below shows the assumed probability distribution for each sub-parameter that has been used to set caps and collars to apply for the forthcoming regulatory control period, as well as the proposed targets, collars and caps for each of the SC parameters, using the methodology described above. Due to our strong historical performance across the majority of sub-parameters, we are adopting more challenging thresholds for the 2023-27 regulatory control period.

Table 7-3: Proposed Service Component targets, collars and caps

Parameter	Sub-parameter	Preferred Distribution	Cap	Target	Collar
Average Circuit Outage Rate	Lines event rate - fault	Normal	11.6%	17.38%	23.2%
	Transformer event rate - fault	Logistic	6.6%	11.70%	17.5%
	Reactive plant event rate - fault	InvGauss	15.5%	19.88%	31.7%
	Lines event rate - forced	Normal	1.9%	11.84%	21.8%
	Transformer event rate - forced	Laplace	7.3%	11.85%	16.1%
	Reactive plant event rate - forced	Normal	24.7%	30.69%	36.6%
Loss of Supply Event Frequency	Number of events greater than 0.05 system minutes per annum	Poisson	0	1	3
	Number of events greater than 0.30	Poisson	0	1	2

Parameter	Sub-parameter	Preferred Distribution	Cap	Target	Collar
	system minutes per annum				
Average Outage Duration	Average outage duration	InvGauss	19	53	159
Proper Operation of Equipment	Failure of protection system	Poisson	23	32	42
	Material failure of SCADA	Poisson	0	1	2
	Incorrect operational isolation of primary or secondary equipment	Poisson	2	6	11

7.3.1.5 Market Impact Component

As already noted, we have concerns with how the MIC will be applied to AusNet Services in the forthcoming regulatory control period given the rapid changes in the Victorian transmission network and our limited ability to respond. As outlined above, we are currently working with the AER to ensure we have access to the options available to other TNSPs to maintain the incentive to minimise the market impact of our outages over the next regulatory period and deliver our capex and opex programs – with a key issue being the ability to recover costs of unforeseen network support contracts.

If these issues are unable to be resolved, such that AusNet Services does not have the flexibility to respond to the incentives provided by the MIC, we favour the removal of the MIC for the next regulatory control period.

Notwithstanding this, this section sets out the calculation of the key parameters of the MIC for the next regulatory control period.

Under Version 5 of the STPIS, the MIC provides a bonus or penalty of up to 1% of MAR each year depending on the performance against the market impact parameter.

In accordance with Appendix F of the STPIS, the key parameters for the MIC to apply to us during the 2023-27 regulatory control period will be calculated as follows:

- Performance is measured as the number of dispatch intervals during a calendar year where an outage on the TNSP's network results in a network constraint with a marginal value greater than $10/MWh;
- The performance target for the MIC is set equal to the average of the median five years from the last seven years of actual performance;
- Caps and collars are set equal to zero and twice the performance target, respectively;
- The unplanned outage event limit is 17% of the performance target; and
- The dollar per dispatch interval is equal to 1% of the MAR for the first year of the regulatory control period divided by our performance target.

The performance target to apply from April 2022 will be based on average performance of the median five years from 2013-19. Accordingly, our cap, target, collar, unplanned outage event limit and dollar per dispatch interval figure for the MIC that will apply during the 2023-27 regulatory control period is set out in the table below. The performance measures in 2016 and 2018 are the maximum and minimum values respectively, throughout the performance period and have accordingly been removed to enable calculation of the MIC target.

Table 7-4: Proposed MIC parameters

Calendar year	Adjusted performance measure
2013	745
2014	871
2015	969
2016	~~6,690~~
2017	4,495
2018	~~318~~
2019	1,984
Parameter	**Dispatch intervals**
Target	1,813
Cap	0
Collar	3,626
Unplanned outage event limit	308
Dollar per dispatch interval	$3,070/DI

Key exclusions to be applied during the 2023-27 regulatory control period

We have undertaken a thorough review of the energy system transformation changes and the resulting effect on our MIC performance. The projected substantial changes in generation mix and an increased uptake of distributed energy resources (DER) in Victoria are also expected to contribute further complications for future MIC performance. These changes are creating additional and more complex system security challenges for our transmission network, necessitating the introduction of numerous constraints, and reducing the effectiveness of the MIC.

If the MIC is to be applied to AusNet Services during the 2023-27 regulatory control period, we encourage the AER to apply the following exclusions listed below in the manner we have described. This will provide certainty that the challenging conditions described in this chapter are taken into consideration when MIC performance is being assessed during the 2023-27 regulatory control period. In the case of exclusion clauses 1, 3A and 11, it would also ensure consistency with the AER's recent annual STPIS compliance decisions.

7.3.1.5.1 Exclusion 1: Frequency constraints arising from changes to AEMO Power System management policy

We submit that the Frequency Control Ancillary Service (FCAS) constraints directed by AEMO, which were excluded during the current regulatory control period, should continue to be excluded during the forthcoming 2023-27 regulatory control period. These outages relate to assets associated with the VIC-SA interconnector. Under the Rules, AEMO is responsible for the planning of the Victorian transmission network and as a result, these constraints remain outside our control as we must comply with AEMO's requirements. We, therefore, propose that these constraints continue to be excluded from annual performance during the 2023-27 regulatory control period under the force majeure exclusion clause.

We also consider that the application of exclusion clause 1 (force majeure) designed to address the 50 MW constraints that significantly arose in 2019, to continue in the forthcoming regulatory control period. Due to continuing developments introduced by AEMO to manage power system frequency in South Australia, outages could lead to new or alternative constraints being introduced, which would not be captured in our target based on historical performance. Certain constraints (those associated with managing power system frequency in South Australia, following the 2015 South Australia separation event) have been previously excluded in 2019 using exclusion code 1 (force majeure). This is consistent with the AER's final decision to remove the constraints (F_S+LREG_0035 and F_S+RREG_0035), which were introduced by AEMO following the separation event, from the target and performance measure during the 2017–22 regulatory control period, therefore continuing to exclude these would be in-principle consistent with the AER's STPIS decision at for the current regulatory control period.[93] These future constraints should also be excluded from our performance through the application of the force majeure exclusion if and when they occur. This will ensure that our performance is not materially impacted by changes to AEMO's Power System management policy, which are outside our scope to control or mitigate.

7.3.1.5.2 Exclusion 3A: Outages for works required to connect new generation sources

The application of this exclusion clause is consistent with the approach taken by the AER in recent annual submissions, which was to exclude constraints associated with contestable projects (AEMO directed or generator connection) as well as non-contestable AEMO projects. The technical characteristics of the transmission system are further changing as a result of strong investor interest in western parts of Victoria, which is shifting the geographic footprint of supply sources away from existing long-standing generation located in the Latrobe Valley, while also increasing penetration of non-synchronous generation. This presents significant network challenges, as integrating large volumes of new renewable generation projects are being compounded by connection of these new projects in weaker parts of the network, where the highest quality renewable fuel sources are available. These locations within our network were not originally designed to handle high volumes of generation, or to withstand the technical characteristics associated with renewable generation technology.

During the current regulatory control period, several AEMO initiated projects have required outages to be taken on our network in order to facilitate the works. The BATS-MLTS 3rd line project conducted in 2017 and the OX1 Line uprating project conducted in 2019, are two recent examples where outages have been taken and excluded by the AER during the review process. We consider this approach should be maintained in relation to further AEMO initiated projects that take place during the next regulatory control period.

With regards to generator connections, we took several outages in 2018 in order to facilitate the connection of new generators to the North West Victorian 'loop'. The connection of these generators impacted the existing communications infrastructure, and we were required to upgrade the communications equipment to ensure NER compliance which resulted in additional outages. These outages would not have otherwise occurred if the renewable generation facilities did not require connection to our transmission network. Therefore, the treatment of these outages is consistent with exclusion clause 3A as the outages were primarily caused by the connection of a new asset not providing prescribed transmission services. We consider that the same principles should apply to capital works delivered during the forthcoming period that are required to facilitate the connection of additional renewable generation.

7.3.1.5.3 Exclusion 4: Treatment of contestable assets

In Victoria, contestable arrangements exist for network augmentations where the construction, ownership and operation of new transmission assets is competitively tendered. Throughout this process, these new transmission assets will require new outages on the prescribed transmission network which have not been recorded before. This indicates that our historical performance outcomes are not a meaningful base (as they would not have captured these new outages) on which to assess future performance against.

The AER has previously made clear that outages related to the connection of the unregulated asset can be excluded, however, outages during the operational period appear to be included

[93] AER, *Final decision – AusNet Services transmission determination 2017-22, Attachment 11: Service target performance incentive scheme*, April 2017, p.15-16.

where AusNet Services is the owner of the unregulated assets.[94] We anticipate that there will be instances where unregulated assets will require operating and maintenance works which will have a flow-on impact on the regulated transmission network in the form of outages, resulting in potential MIC penalties. This disadvantages AusNet Services during the tendering process for contestable projects and places us on an unequal footing with other service providers that do not face the same potential MIC penalties associated with operational outages on contestable assets. Other service providers operating in Victoria do not have to account for these penalties when bidding for contestable projects by virtue of the fact that they are not subject to the STPIS. We would welcome a discussion with the AER on the appropriate application of this exclusion clause, in the instance where outages on the prescribed transmission network occur as a result of operation and maintenance on unregulated assets. We consider these outages ought to be excluded to place all contestable providers on equal footing.

7.3.1.5.4 Exclusion 6: Operational security constraints

AEMO is requesting outages not be taken concurrently for operational security risks driven by the reduction of power system security as a result of increased inverter-based generation, with Victoria being one of the most heavily affected regions within the NEM. The minimum demand issues, coupled with the insistence on non-renewable generators taking outages during spring and autumn, results in significant restrictions on our ability to take concurrent outages on assets. For example, in 2019 alone:

- The MLTS-SYTS outage was cancelled in spring due to the lack of system strength (due to the continued security risk during spring and autumn);
- The timing of the MLTS line reactor outage to only occur when minimum demand issues are avoided, means planning a continuous outage is increasingly challenging.

Historical constraints used to manage system security do not sufficiently address all the risks posed by inverter-based generation. The number of additional constraints associated with operational security have steadily increased and these changes increase the likelihood of constraints binding during planned outages and mean that it is increasingly difficult to optimise our planned outages in a reasonable window of opportunity, as the MIC encourages. This has resulted in a situation where the available windows of opportunity are both inadequate and insufficient for us to conduct our planned network outages safely and reliably.

These outages have previously been coordinated to reduce the market impact where possible, but without an appropriate exclusion, may result in increased binding constraints. As these constraints are not reflected in the historic performance that will be used to set our target for the forthcoming regulatory period, this creates significant challenges for our ability to manage outages in areas with rising inverter-based generation. As a result of these outages not being factored into the performance target, a suitable measure for dealing with these constraints would be via the exclusion clause concerned with operational security.

7.3.1.5.5 Exclusion 11: Individual participant constraints

The primary use of this exclusion clause is consistent with the approach taken in the 2018 and 2019 annual submissions, in that any constraint that constrained an individual participant has been excluded. Since these outages were only taken within the optimum window for routine maintenance, the AER agreed with the approach taken and this was reflected in their decisions in the respective reviews.

The significant upturn in constraints of this nature, and the inability to plan for these types of constraints, as well as the inability to observe these constraints in real-time due to the privacy of

[94] AER, *Final Decision – Electricity transmission network service providers service target performance incentive scheme*, September 2015, pg. 34.

generator bids has led to an increased reliance of this exclusion clause. We will continue to undertake maintenance work where all impacts to customers and the market are minimised as far as practically possible, however, due to the aforementioned energy system changes there will invariably be instances where generator outages do not align with our network. Accordingly, individual participant constraints are highly likely to continue to occur in the forthcoming regulatory control period and we will seek to exercise exclusion clause 11 in these instances where applicable.

7.3.1.6 Network Capability Component

As already noted, the NCC provides an incentive of up to 1.5% of maximum allowable revenue each year to fund projects that improve the capability of the transmission network at times when it is most needed. The incentive payment is calculated as 1.5 multiplied by proposed expenditure. TNSPs must submit a Network Capability Incentive Parameter Action Plan (NCIPAP) for approval by the AER, which contains:

- A list of every transmission circuit and injection point on the network, and the reason for the limit for each; and
- A list of priority projects to be undertaken during the forthcoming regulatory control period to improve the limits for these transmission circuits and injection points.

AEMO plans the transmission network in Victoria. Therefore, the NCIPAP has been prepared jointly with AEMO.

We have also consulted with AEMO under Clauses 5.4(e) and (g) of the STPIS. The outcome of this review is outlined in Appendix 7C: AEMO Endorsement letter.

We note that the assessment of a small number of certain transmission circuits and injection points will be investigated further once the forthcoming 2020 network demand forecasts and the Victorian Annual Planning Report (VAPR) are published. These are key inputs into the process of identifying NCIPAP projects that offer positive net market benefits during the next regulatory period. We will consult with our customers and stakeholders on the findings of this investigation as part of our post-lodgement engagement program in 2021 and incorporate any updates to our NCIPAP into our Revised Revenue Proposal.

During the current regulatory period, AusNet Services has introduced a number of additional NCIPAP projects to respond to changes in constraints across the network, as a result of the rapid pace of change to the energy system. We strongly support this feature of the scheme, which provides flexibility to address emerging issues within period, benefiting customers.

At this time, we have not identified any priority projects for inclusion in the NCIPAP. As noted above, if priority projects are identified as a result of ongoing assessment of network limits and emerging constraints, we intend to present these to the AER, our customers, and other stakeholders in early 2021.

7.4 Efficiency Benefit Sharing Scheme

The purpose of the EBSS is to provide a mechanism for the sharing between network service providers and customers of efficiency gains and losses relating to operating expenditure during the regulatory control period. The design of the scheme ensures that network service providers face a consistent incentive to deliver efficiency savings in each year of the regulatory control period. Assuming a five-year regulatory control period, the effect of the scheme is to share efficiency savings (or additional efficient costs) in the ratio of 70:30 between customers and the network business.

This section sets out:

- The calculation of the current period's efficiency carryover amount, which will be recovered during the forthcoming period; and

- Our proposal for the operation of the EBSS in the next period.

7.4.1 Current period carry over amount

We have calculated the efficiency carryover amount to be recovered during the forthcoming regulatory control period in accordance with the AER final decision and determination on the application of the EBSS for both the 2014-2017 and 2017-2022 regulatory control periods.

This calculation involved the following steps:

- Determining opex for the EBSS for 2014-15 to 2020-21, which is equal to total opex excluding debt raising costs and applying the following exclusions, consistent with the AER's treatment of these costs during the current period:
  - Easement land tax;
  - Self-insurance from 2014-15 and 2016-17;[95]
  - Rebates under the Availability Incentive Scheme;
  - Priority projects approved under STPIS network capability component;
  - Merits review opex; and
  - Movements in provisions related to opex.
- Calculating the efficiency carryover amount by comparing 2017-2022 controllable opex with the adjusted regulatory allowances.

The 2021-22 actual opex uses the approach set out in the AER Reset RIN and consistent with our choice of 2020-21 as our base year as follows:

Estimated 2021-22 Opex = $F_{2021\text{-}22} - (F_{2020\text{-}21} - A_{2020\text{-}21})$

where $F_{2021\text{-}22}$ is forecast opex for 2021-22, $F_{2020\text{-}21}$ is forecast opex for 2020-21, and $A_{2020\text{-}21}$ is actual opex for 2020-21.

To note, in calculating the EBSS carryover amount, we have altered the Reset RIN by updating the CPI index for recent actuals and forecasts for 2020-21 and 2021-22 according to the RBA's latest Statement of Monetary policy, released in August 2020.[96]

7.4.1.1 Compliance with Section 71YA of the NEL

We are required to comply with Section 71YA of the NEL. This requires that where any expenditure or cost has been incurred or is forecast to be incurred by us as a result of or incidental to a review under Division 3A – Merits review and other non-judicial review – of the NEL, we must identify the expenditure or cost and provide a statement attesting that we have not:

- Included any of that expenditure or cost, or any part of that expenditure or cost, in the capital or operating expenditures contained in our regulatory proposal; and
- Recovered or sought to pass-through any of that expenditure or cost, or any part of that expenditure or cost, from end users.

We reviewed our actual opex and identified that costs were incurred as a result of or incidental to merits review or other non-judicial review. To ensure compliance with Section 71YA of the NEL

[95] This exclusion has been made consistent with the AER's 2013-2017 decision. The AER's 2018-22 final decision ruled that self-insurance was not to be excluded from the EBSS, so we have not excluded it from FY2018 onwards consistent with this decision.

[96] As our financial years take place from April of each year, we use the March quarter to calculate the change in the CPI. To forecast the March quarter index, we use the average of the previous December and upcoming June RBA forecasts, given the RBA does not forecast March quarters.

we have removed this expenditure from our opex for the purposes of calculating the EBSS, which is reflected in Table 7-5.[97]

7.4.1.2 Calculation of EBSS carryover amount

The following table sets out the calculation of our incremental efficiency gains and losses in the current period.

Table 7-5: Calculation of EBSS incremental efficiency gains/losses ($M, real 2021-22)

	2014-15	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
Total opex (excluding debt raising)	**210.0**	**215.3**	**231.9**	**235.5**	**258.2**	**245.5**	
Less							
Easement land tax	116.1	121.2	145.5	143.2	176.1	164.0	
Self-insurance	1.0	1.9					
Rebates under the Availability Incentive Scheme	2.7	0.2	0.1	0.2	0.3		
Priority projects approved under STPIS network capability component	0.3	0.4	0.0	0.0	0.0	0.0	
Movements in provisions related to opex	-0.1	-1.5	-2.1	4.7	-5.0	0.0	
Merits review opex	0.0	0.2	0.1	0.0	0.0	0.0	
Opex for EBSS purposes	**90.2**	**93.0**	**88.3**	**87.3**	**86.8**	**81.5**	**82.0**
Approved allowance	**88.8**	**92.2**	**97.3**	**97.8**	**98.9**	**99.1**	**99.6**
Incremental efficiency gain/loss			**8.5**	**1.5**	**1.6**	**5.5**	**0.0**

Source: AusNet Services

Note: 2014-15 to 2019-20 data are actuals, 2020-21 data is estimated. 2014-15 was the base year for the current regulatory period. Total opex excludes debt raising costs for all years and NCIPAP operating expenditure for years 2017-18 to 2019-20. 2020-21 movement in provisions and NCIPAP operating expenditure is not currently forecast but will be accounted for in our Revised Revenue Proposal.

The following table shows how the above incremental efficiency savings have been used to determine the proposed carryover amount.

[97] ANT - TRR 2023-27 RIN Workbook 6 EBSS - 29 October 2020.

Table 7-6: Calculation of EBSS carryover amount ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
FY18	8.5	0.0	0.0	0.0	0.0	
FY19	1.5	1.5	0.0	0.0	0.0	
FY20	1.6	1.6	1.6	0.0	0.0	
FY21	5.5	5.5	5.5	5.5	0.0	
FY22	0.0	0.0	0.0	0.0	0.0	
Total carryover amount	**17.1**	**8.5**	**7.1**	**5.5**	**0.0**	**38.1**

Source: AusNet Services

7.4.2 Application of the EBSS in the 2023-27 regulatory control period

We propose to apply the same treatment to the EBSS in the forthcoming period as outlined for the current period above. This involves excluding, where applicable:

- Easement land tax;
- Debt raising costs;
- Priority projects approved under STPIS network capability component;
- Rebates under the Availability Incentive Scheme; and
- Movements in provisions related to opex.

7.5 Capital Expenditure Sharing Scheme

This section sets out our proposal with respect to the application of the Capital Expenditure Sharing Scheme (CESS). It sets out:

- The calculation of the current period's efficiency carryover amount, which will be recovered during the forthcoming period; and
- Our proposal for the operation of the CESS in the next period.

7.5.1 The current period carryover amount

We have calculated the efficiency carryover amount to be recovered during the forthcoming regulatory control period in accordance with the AER's final decision and determination on the application of the CESS for the 2017-22 period. This calculation involved the following steps:

1. Calculate the capex applicable to the CESS, by removing asset disposals from total capex.
2. Calculate the cumulative underspend amount for the current regulatory control period in net present value terms.
3. Apply the sharing ratio of 30% to the cumulative underspend amount to work out what our share of the underspend should be.
4. We calculate the CESS payments taking into account the financing benefit of the underspend.

Note that actual capex for the purposes of the CESS calculation includes capitalised lease costs reported for the current regulatory control period, including $44 million in 2019-20. This change in our capitalisation policy is discussed further in Chapter 8.

Table 7-7: Calculation of CESS carryover amount ($M, nominal)

	2017-18	2018-19	2019-20	2020-21	2021-22
Capex allowance	186.3	165.8	164.2	156.5	120.3
Actual capex	131.0	145.0	192.3	155.3	134.8
Underspend	55.3	20.8	-28.1	1.2	-14.5
Year 1 benefit		1.8	1.9	1.9	1.9
Year 2 benefit			0.7	0.7	0.7
Year 3 benefit				-0.9	-0.9
Year 4 benefit					0.0
Year 5 benefit					
NPV underspend	68.4	24.4	-31.5	1.3	-14.5
NPV financing benefit	0.0	2.2	2.9	1.7	1.7
Total underspend (NPV) adjusted for deferrals	48.1				
Relevant sharing ratio	0.3				
Consumer share	33.7				
NSP share	14.4				
Total NSP financing benefit (NPV)	8.4				
NPV of CESS payments (post-adjustment)	6.0				
CESS payment (real 2021-22)	1.3	1.3	1.3	1.3	1.3

Source: AusNet Services

7.5.2 Application of the CESS in the 2023-27 regulatory control period

In the Framework and Approach Paper, the AER stated that it intends to apply the CESS to AusNet Services in the 2023-27 regulatory control period. We endorse that position.

7.5.2.1 Proposed capex for the CESS

Table 7-8 below sets out the proposed capex for the CESS in the 2023-27 regulatory control period.

Table 7-8: Proposed capex for the CESS ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27
Forecast net capex	177.1	180.7	179.1	144.5	114.5

Source: AusNet Services

7.6 Supporting documentation

We have included the following documents to support this chapter:

- Appendix 7A - Fitting Probability Distributions for Service Component Data.
- Appendix 7B - Network Capability Incentive Parameter Action Plan.
- Appendix 7C - AEMO NCIPAP Endorsement Letter.

8 Opening regulatory asset base

8.1 Key points

The key points in this chapter are:

- The Regulatory Asset Base (RAB) has been calculated in accordance with the NER and the AER's Roll Forward Model (RFM) and Post Tax Revenue Model (version 4) (PTRM).
- Our opening RAB for the 2023-27 regulatory control period includes a transfer of insulators and instrument transformers from their existing asset classes to new asset classes in order to apply their economic lives for calculating the depreciation allowance.
- Our opening RAB also includes a final year adjustment that principally relates to the roll-in of prescribed assets contracted outside the revenue cap in the previous period (known as growth assets[98]).

8.2 Chapter structure

This chapter is structured as follows:

- Section 8.3 explains how our opening RAB accounts for past capital expenditure;
- Section 8.4 explains how we have calculated our opening RAB as at 1 April 2022;
- Section 8.5 provides a summary of our RAB over the 2023-27 regulatory period; and
- Section 8.6 summarises our supporting documentations.

8.3 Review of past capital expenditure

Clause S6A.2.2A of the NER permits the AER to review past capital expenditure (capex) in specific circumstances and exclude some capex from the RAB. For the purposes of this capex review, the relevant review period is 1 April 2015 to 31 March 2020.[99]

Under clause S6A.2.2A(b)(1), the AER is permitted to review past capex if the actual total expenditure over the review period exceeds the AER's allowance (adjusted for approved pass-through amounts), and the AER is not satisfied that part or all of the capex overspend reasonably reflects the capital expenditure criteria.

For this review period, clause S6A.2.2A(b)(1) is not satisfied because we have not overspent against our approved capex allowance (adjusted for approved pass-through amounts). No other circumstance in which the AER is permitted to review past capex is satisfied.[100] As such, all the capex we incurred during the review period is automatically included in the RAB.

We have also included our forecast of actual capex for the period 1 April 2020 to 31 March 2022 in the RAB. We note that capex for these years will form part of the review period at the next reset.

[98] Previously known as group 3 assets.

[99] Clause S6A.2.2A(a1) of the NER.

[100] Clauses S6A.2.2A(b)(2) and (3) of the NER are not satisfied so a review of past capex is not required.

8.4 Opening RAB as at 1 April 2022

Our opening RAB has been calculated in accordance with the NER and the AER's standard regulatory approach.

As our actual capital expenditure for the final two years of the current regulatory period (1 April 2020 to 31 March 2022) is not yet known, our opening RAB in this Revenue Proposal reflects forecast information. Our Revised Regulatory Proposal will be updated for actual capex data that becomes available for 2020-21. Additionally, an adjustment to the forecast information will need to be made in the subsequent TRR reviews.

We also note that our inflation rate for 2020-21 will be updated in our Revised Regulatory Proposal, to reflect actual inflation rate inputs that becomes available.

The calculation of the opening RAB for 1 April 2022 involves the following standard steps:

- Adopt the approved opening RAB as at 1 April 2017.
- Add actual and forecast capex (net of disposals) for the 2017-22 regulatory control period.
- Deduct forecast straight-line depreciation for the 2017-22 regulatory period.
- Add RAB indexation for the 2017-22 regulatory period.
- Adjust for the difference between actual and forecast capex (net of disposals) in 2016-17.
- Add in the final year asset adjustments, which are primarily due to the roll-in of growth assets.[101]

Table 8-1 sets out our proposed RAB for the current regulatory period.

In accordance with the calculation in Table 8-1, our proposed opening RAB as at 1 April 2022 is $3,582 million. As noted earlier, the opening RAB will be updated in our Revised Regulatory Proposal to reflect actual data that becomes available.

As discussed in Chapter 9 of this Revenue Proposal, we have transferred insulators and instrument transformers from their parent asset classes to new asset classes in order to apply more appropriate asset lives to these assets. While a transfer of these assets will change the value within each asset class affected, it will not impact or change the overall opening RAB. As a result, we have not described the impact of these transfers here.

[101] As explained in Chapter 9 of this Revenue Proposal, we have transferred some assets from their parent asset classes into new asset classes for accelerated depreciation. While the final year asset adjustments in our RFM reflects these transfers, the net impact to the opening RAB is zero.

Table 8-1: Regulatory asset base roll forward, as incurred, to 1 April 2022 ($M, nominal)

	2017-18	2018-19	2019-20	2020-21	2021-22
Opening RAB (1 April)	3,170.0	3,188.1	3,221.4	3,290.1	3,322.1
Capex (net of disposals)	131.0	147.6	197.4	154.9	134.5
Forecast straight-line depreciation	-170.9	-174.3	-182.7	-186.0	-169.5
RAB indexation	58.0	60.1	53.9	63.1	62.3
Difference between actual and forecast capex from 2016-17[102]	0.0	0.0	0.0	0.0	-45.5
Forgone return on difference	0.0	0.0	0.0	0.0	-13.1
Final year asset adjustments[103]	0.0	0.0	0.0	0.0	291.1
Closing RAB (31 March)	**3,188.1**	**3,221.4**	**3,290.1**	**3,322.1**	**3,581.9**

Source: AusNet Services

As noted above, our opening RAB for 1 April 2022 includes several final year asset adjustments, which are explained in further detail in section 8.4.3.

8.4.1 Actual and forecast net capex, 1 April 2017 to 30 March 2022

The RAB roll forward calculation requires a combination of actual and forecast capex (net of disposals) as shown in Table 8-2. Actual costs and disposals information reconcile with the nominal values reported in the Annual Regulatory Accounts.

Table 8-2: Proposed capex net of asset disposals, as incurred ($M, nominal)

	2017-18	2018-19	2019-20	2020-21	2021-22
Gross capex	133.7	144.5	199.6	151.2	131.4
Disposals	-6.0	-0.6	-7.0	-0.2	-0.2
Capex net of disposals	127.7	143.8	192.6	151.0	131.1
Net capex recognised in RAB	**131.0**	**147.6**	**197.4**	**154.9**	**134.5**

Source: AusNet Services

8.4.2 Regulatory depreciation

For the current regulatory control period, we have applied depreciation on a forecast basis consistent with the approach required under the Capital Efficiency Sharing Scheme (CESS). This is consistent with the AER's position.[104]

Regulatory depreciation is calculated by determining the nominal straight-line depreciation and offsetting the CPI indexation for each asset class. The calculation of each of these elements is set out below.

[102] This includes our growth asset differences.

[103] The final year asset adjustments are primarily due to the roll-in of growth assets.

[104] AER 2015, *Framework and approach for AusNet Services Regulatory control period commencing 1 April 2017*, April 2015, p. 29.

8.4.2.1 Forecast straight-line depreciation

We have sourced the straight-line depreciation forecasts (in 2016-17 dollars) by asset class from the most recent PTRM for the current regulatory control period. The PTRM containing these forecasts includes the annual cost of debt updates and our approved expenditure allowances for the January 2020 transmission tower collapse cost pass-through event. We input these forecasts into the AER's RFM and adjusted them for actual and forecast inflation. The table below shows the calculation.

Table 8-3: Forecast straight-line depreciation

	2017-18	2018-19	2019-20	2020-21	2021-22
Forecast straight-line depreciation (real 2016-17)	168.7	169.0	173.8	174.1	155.6
Actual / forecast inflation	2.2	5.3	8.9	11.9	13.9
Forecast straight-line depreciation ($M, nominal)	**170.9**	**174.3**	**182.7**	**186.0**	**169.5**

Source: AusNet Services

8.4.2.2 Actual and forecast indexation

Clause 6A.6.1(e)(3) of the NER requires that the RAB be adjusted for actual outturn inflation consistent with the method that was used in its transmission determination. We have therefore used actual and forecast CPI to escalate the RAB over the current regulatory control period in accordance with the approach outlined in the AER's determination for this period.

The AER's final decision defined a change in CPI to be the annual percentage change in the ABS CPI all groups, weighted average of eight capital cities from the September quarter in year t–2 to the September quarter in year t–1.[105] See Table 8-4 for the CPI we used to escalate the RAB.

Table 8-4: Actual and forecast inflation

	2017-18	2018-19	2019-20	2020-21	2021-22
Partially lagged inflation	1.83%	1.89%	1.67%	1.92%	1.88%

Source: AusNet Services.

For roll forward purposes we have applied the partially lagged inflation approach for both opening RAB indexation and converting 2016-17 dollars to nominal values.[106] See Table 8-5 for our proposed RAB indexation using the partially lagged inflation approach.

Table 8-5: RAB indexation ($M, nominal)

	2017-18	2018-19	2019-20	2020-21	2021-22
RAB indexation	58.0	60.1	53.9	63.1	62.3

Source: AusNet Services.

8.4.2.3 Summary of regulatory depreciation

Using the information from sections 8.4.2.1 and 8.4.2.2 above, our proposed regulatory depreciation amounts for the current period are set out in Table 8-6.

[105] AER 2017, *AusNet Services transmission determination 2017-22*, April, pp. 6, 8.

[106] The partially lagged inflation approach uses inflation lagged by one year for some elements with the RFM.

Table 8-6: Regulatory depreciation ($M, nominal)

	2017-18	2018-19	2019-20	2020-21	2021-22
Forecast straight-line depreciation	170.9	174.3	182.7	186.0	169.5
RAB indexation	-58.0	-60.1	-53.9	-63.1	-62.3
Regulatory depreciation	**113.0**	**114.2**	**128.7**	**122.9**	**107.2**

Source: AusNet Services

8.4.3 Forecast final year asset adjustments

We are proposing several end of period adjustments that can be summarised as follows (also see Table 8-7):

- Transferring $179 million of insulators and $292 million of instrument transformers from their existing parent asset classes into new asset classes.
- Rolling in $294 million of growth assets, reflecting their actual depreciated value as at 1 April 2022. The inclusion of growth assets is the process by which certain transmission system augmentations used to provide prescribed transmission services and undertaken during a regulatory control period are rolled into the RAB. The roll-in of growth capex is the total actual growth asset expenditure up to 31 December 2019 that has not been rolled into the RAB in previous resets. A list of the assets and their values is provided at Appendix 5A Growth Assets. Chapters 1 and 5 of this Revenue Proposal provides further information about the arrangements that apply to growth asset augmentations.

Table 8-7: Final year adjustments

Asset class	Final year adjustments ($M, nominal)	Remaining asset life of adjustments to RAB (years)
Secondary	26.8	10.1
Switchgear	-221.3	33.1
Transformers	60.1	39.7
Reactive	13.4	34.7
Towers and Conductor	-104.6	35.6
Establishment	44.1	39.6
Communications	0.4	9.7
other (non-network)	2.9	4.2
Inventory Adjustment (Other non-network)	-1.9	0.0
Insulators - Already Decommissioned	8.4	1.0
Insulators - Decommission 2023-2027	2.9	5.0
Insulators	167.6	18.1
Instrument Transformers - Already Decommissioned	13.1	1.0
Instrument Transformers - Decommission 2023-2027	4.4	5.0
Instrument Transformers	274.7	26.1
Total	**291.1**	

Source: AusNet Services

8.4.4 Capitalised leases

We have historically treated our property and motor vehicle lease expenses as opex by recording the annual lease payments on a straight-line basis, in accordance with the lease term. The Australian Accounting Standard Board (AASB) recently introduced AASB 16, which is applicable to annual reporting periods beginning on or after 1 January 2019. The effect of this change is that, from 1 April 2019 (the start of our financial reporting year), the full amount of a lease, where we are the lessee, must be capitalised up-front when it is first entered into or renewed, and amortised over its lease term. From a cashflow perspective, the accounting change has no impact. However, the income statement will show rental expenses replaced with interest and depreciation expenses.

From 1 April 2019, we commenced recognising the present value of the remaining lease payments of all existing lease arrangements as an asset for the ‘right to use’ the leased asset while also recognising a liability to make lease payments for the same amount over the same period. These assets recorded in our financial asset register have been assigned useful lives equivalent to the underlying lease terms.

Consistent with the approach taken in the statutory accounts, this approach has been applied to the 2019-20 regulatory accounts, regulatory determination reset RIN, and regulatory models. That is, this Revenue Proposal treats all existing leasing arrangements as capital expenditure from 1 April 2019. The required adjustments to the opening RAB are described in the following section.

We previously leased motor vehicles which were reported as opex in both the statutory accounts and RINs. Since then, we have purchased our own fleet of motor vehicles. We now own all our motor vehicles, and we do not have any current leases. Therefore, we have not proposed to capitalise any motor vehicles leases.

8.4.4.1 Capitalised lease actuals and forecasts

In 2019-20, we capitalised our existing leases that relate to prescribed transmission services, by creating two new asset classes. One asset class reflects leases with a remaining asset life of less than 20 years, and another greater than 20 years. In total, we capitalised 41 existing leases (31 leases with a remaining asset lives of less than 20 years and 10 leases greater than 20 years) including office buildings, car parks, radio stations, switchyards, communications towers, access tracks, and land. These two classes of capitalised leases are consistent with the restated 2019-20 Annual RIN submitted as a supporting document.

We have also created new asset classes, for capitalised leases, for each year from 2022-23 to 2026-27. These new asset classes, from 2022-23 to 2026-27, do not differentiate between leases greater or less than 20 years.

Table 8-8 below contains the capitalised lease amounts starting from 1 April 2022 through to 31 March 2027.

Table 8-8: Capitalised leases, as incurred ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27
Leases capitalised	0.0	1.1	-	0.1	0.3
Average RAB lives (years)	25.0	19.0	n/a	31.8	15.4

Source: AusNet Services

8.5 Forecast RAB over the 2023-27 period

Our opening RAB as at 1 April 2022 is rolled forward over the 2023-27 regulatory control period to reflect our capex forecast, straight-line depreciation forecast and the indexation of the RAB.

The calculations, which are consistent with the AER's RFM and PTRM (Version 4), are summarised in the table below.

Table 8-9: Forecast RAB over the 2023-27 regulatory period ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27
Opening RAB	3,581.9	3,655.3	3,751.9	3,840.8	3,885.6
Capex net of disposals	183.0	190.8	193.2	159.4	129.0
Straight-line depreciation	-190.2	-176.4	-188.6	-201.0	-209.8
RAB indexation	80.5	82.2	84.4	86.4	87.4
Closing RAB	**3,655.3**	**3,751.9**	**3,840.8**	**3,885.6**	**3,892.2**

Source: AusNet Services

In accordance with clause S6A.2.1(f)(4) of the NER, only actual and estimated capital expenditure properly allocated to the provision of prescribed transmission services in accordance with our approved CAM is included in the RAB.

8.6 Supporting documentation

We have included the following documents to support this chapter:

- AusNet Services' Post Tax Revenue Model;
- AusNet Services' Roll Forward Model;
- AusNet Services' Standalone Depreciation Model;
- Appendix 5A - Growth Assets.

9 Depreciation

9.1 Key points

The key points in this chapter are:

- We are using the AER's year-by-year tracking model for depreciating the opening RAB.
- Our analysis demonstrates that a depreciation schedule based on the current standard lives of insulators[107] and instrument transformers (60 years and 45 years respectively) is inconsistent with clause 6A.6.3(b)(1) of the NER. This is because the current standard asset lives do not reflect the nature or category of the assets over the economic life of that asset.
- For the reason above, we are proposing to introduce six new asset classes. This enables AusNet to put forward a depreciation proposal for each new asset class that is consistent with clause 6A.6.3(b)(1) of the NER. The six new asset classes and the proposed depreciation schedule for each are:
    - For insulators and instrument transformers that we have already decommissioned, we propose to fully depreciate their residual values in the first year of the 2023-27 regulatory control period (2 new asset classes).
    - For insulators and instrument transformers that we plan on decommissioning during the 2023-27 regulatory period, we propose to fully depreciate their residual values by the end of the 2023-27 regulatory control period (2 new asset classes).
    - For the balance of insulators and instrument transformers (i.e. in-service assets), we propose a depreciation profile that reflects an economic life of 40 years and 38 years respectively (2 new asset classes).

9.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 9.3 provides a high-level overview of why our depreciation proposal satisfies the NER;
- Section 9.4 presents a high-level overview of our depreciation methodology;
- Section 9.5 provides a brief description of our valuation model;
- Section 9.6 describes the unit rate assumptions used in our valuation model;
- Section 9.7 sets out our depreciation proposal for insulators and instrument transformers that we have already decommissioned;
- Section 9.8 explains our depreciation proposal for insulators and instrument transformers that we plan on decommissioning during the 2023-27 regulatory period;
- Section 9.9 outlines our depreciation proposal for the balance of in-service insulators and instrument transformers;
- Section 9.10 sets out our depreciation proposal for the balance of assets in the opening RAB (no accelerated depreciation);

[107] Transmission line insulators, which we simply refer to as 'insulators' throughout this Revenue Proposal.

- Section 9.11 explains our depreciation proposal for new insulators and instrument transformers in the capex program;
- Section 9.12 describes depreciation proposal for the balance of assets in the capex program (no accelerated depreciation);
- Section 9.13 summarises our proposed depreciation allowance for the 2023-27 regulatory period; and
- Section 9.14 lists the supporting document for this chapter.

9.3 Rules requirements

Clause 6A.6.3(b) of the NER states:

> *The depreciation schedules referred to in paragraph (a) must conform to the following requirements:*
>
> *(1) except as provided in paragraph (c), the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets;*
>
> *(2) the sum of the real value of the depreciation that is attributable to any asset or category of assets over the economic life of that asset or category of assets (such real value being calculated as at the time the value of that asset or category of assets was first included in the regulatory asset base for the relevant* transmission system*) must be equivalent to the value at which that asset or category of assets was first included in the regulatory asset base for the relevant* transmission system*; and*
>
> *(3) the economic life of the relevant assets and the depreciation methodologies and rates underpinning the calculation of depreciation for a given* regulatory control period *must be consistent with those determined for the same assets on a prospective basis in the* transmission determination *for that period.*

A depreciation schedule that conforms with clause 6A.6.3(b) of the NER must be applied to calculate the depreciation for each regulatory year.[108]

Our proposed depreciation schedule satisfies clause 6A.6.3(b)(1) of the NER because it reflects the economic lives of the new asset classes, specifically:

- The remaining economic lives of insulators and instrument transformers that we have already decommissioned is zero. As a result, we propose to fully depreciate their residual values in the first year of the 2023-27 regulatory control period.
- The remaining economic lives of insulators and instrument transformers that we plan on decommissioning during the 2023-27 regulatory control period will decrease to zero the year they are decommissioned. As a result, we propose to fully depreciate their residual values by the end of the 2023-27 regulatory control period.
- For the balance of insulators and instrument transformers that are in-service, we propose to depreciate their residual values over a period that reflect their economic lives of 40 years and 38 years respectively.

If we were to adopt their current standard asset lives (60 years for insulators and 45 years for instrument transformers), assets would be depreciated over a period that is longer than their economic lives and thus inconsistent with clause 6A.6.3(b)(1).

[108] NER, clause 6A.6.3(a).

Our revised depreciation proposal satisfies the requirements of clause 6A.6.3(b)(2) because it proposes to depreciate the residual values of insulators and instrument transformers, which we have estimated using a valuation model. That is, our estimate of the real value of depreciation, for insulators and instrument transformers, proxies the value at which they were first included in the RAB.

It also satisfies clause 6A.6.3(b)(3) because it proposes a different depreciation treatment on a prospective basis, from 1 April 2022 onwards. The current approach, of adopting the standard asset lives of 60 years for insulators and 45 years for instrument transformers, still applies up to 31 March 2022.

9.4 Depreciation methodology

Our proposed methodology for the 2023-27 regulatory control period is consistent with the AER's most recent final determination for our electricity transmission business for the current 2018-22 regulatory period.

We have used the AER's year-by-year tracking model to produce the depreciation inputs to the Post Tax Revenue Model (Version 4) (PTRM) which we have submitted alongside this Revenue Proposal.

Our approach is briefly summarised as follows:

- Calculate the opening RAB as at 1 April 2022.
- Fully depreciate some assets during the 2023-27 regulatory control period:
    - For insulators and instrument transformers that we have already decommissioned, fully depreciate their residual values in the first year of the 2023-27 regulatory period.
    - For insulators and instrument transformers that we plan on decommissioning during the 2023-27 regulatory period, fully depreciate their residual values by the end of the 2023-27 regulatory control period.
- Apply straight-line depreciation to the remaining assets in the opening RAB:
    - For insulators, apply a remaining asset life that reflects an economic life of 40 years.
    - For instrument transformers, apply a remaining asset life that reflects an economic life of 38 years.
    - For all other assets, apply a remaining asset life that reflects the standard asset life approved in the current transmission determination.
- Apply straight-line depreciation to new capex using:
    - An economic life of 40 years for insulators;
    - An economic life of 38 years for instrument transformers; and
    - The standard asset lives approved in the current transmission determination.

We have also described our approach in Table 9-1 below.

Table 9-1: Depreciation methodology

Type	Asset	Replacement status	Depreciation method	Section
Assets in the opening RAB	Insulators	Decommissioned	Fully depreciate in 2022-23	9.7
		Planned for decommissioning during the 2023-27 regulatory period	Fully depreciate their residual values by the end of the 2023-27 regulatory control period	9.8
		Balance, in-service	Depreciate over a remaining asset life that reflects an economic life of 40 years	9.9
	Instrument transformers	Decommissioned	Fully depreciate in 2022-23	9.7
		Planned for decommissioning during the 2023-27 regulatory period	Fully depreciate their residual values by the end of the 2023-27 regulatory control period	9.8
		Balance, in-service	Depreciate over a remaining asset life that reflects an economic life of 38 years	9.9
	All other assets	N/A	Depreciate over a remaining asset life that reflects the standard asset life approved in the current determination	9.10
New capex in the capex program	Insulators		Depreciate over an economic life of 40 years	9.11
	Instrument transformers		Depreciate over an economic life of 38 years	9.11
	All other assets		Depreciate over the standard asset life approved in the current determination	9.12

Source: AusNet Services

9.5 Valuation model

In order to implement the depreciation proposal for insulators and instrument transformers described in section 9.4, we need to estimate the residual value of these assets, then transfer the residual values from their parent asset classes into new asset classes. We have developed a valuation model to calculate the residual values as at 1 April 2022.

The valuation model adopts the following steps:

- Step 1 – establish the total population of the asset as at 1 April 2022;
- Step 2 – estimate the historical annual additions to the RAB;
- Step 3 – apply the current unit replacement cost including capitalised overheads;
- Step 4 – estimate the nominal capex up to 2022; and
- Step 5 – apply a nominal RAB roll forward approach to 1 April 2022. Using our approach, the closing value for each year is the sum of:
    - The opening asset value;
    - Indexation, using actual inflation consistent with the standard roll forward approach;
    - New capex, in nominal dollars; and

- Depreciation, using the current standard asset lives.

Our valuation method is consistent with clause 6A.6.3(b)(2) because the underlying assumptions are a proxy of the values at which the assets were first included in the RAB. It is also consistent with clause 6A.6.3(b)(3) because it applies the current standard asset lives (60 years for insulators and 45 years for instrument transformers) to roll forward the RAB to 1 April 2022. We have only applied our revised economic lives on a prospective basis, from 1 April 2022.

One of the key inputs into our valuation model is the unit rate. See section 9.6 for our unit rate assumptions.

The valuation model and the underlying assumptions are described in further detail in later sections of this chapter.

9.6 Unit rates

The unit rate is a key input into the valuation model.

This section describes the underlying assumptions that we have used to calculate the unit rates. Due to the way our valuation model is set up, the unit rate that is entered into the model needs to be in 2018-19 dollars. As such, the unit rates referred to in this chapter are in 2018-19 dollars.

Insulators

We have applied a unit rate (including overheads) of [C-I-C]. The rate is based on the unit rates pertaining to glass, porcelain and polymeric insulators, weighted by their respective proportions on our transmission network. See Table 9-2.

Table 9-2: Unit rate for insulators

Type	% of network	Unit rate ($2018-19)
Glass	9%	[C-I-C]
Porcelain	63%	[C-I-C]
Polymeric	28%	[C-I-C]
Weighted average unit rate excluding overhead		[C-I-C]
Weighted average unit rate including overhead		[C-I-C]

Source: AusNet Services

Our unit rate for polymeric insulators [C-I-C] is based on the replacement rates contained in Appendix 4A Unit Rates of this Revenue Proposal. Specifically, we calculated the weighted average replacement rate, and divided it by 3.45. This was necessary because the weighted average unit rate is per tower-circuit, whereas we need the unit rate per insulator string. We estimated there are 3.45 insulator strings per tower circuit. We also used the replacement rates in Appendix 4A Unit Rates to derive our capex program. Table 9-3 sets out our weighted average unit rate calculation.

Our unit rate for glass and porcelain insulators is based on our polymeric unit rate multiplied by [C-I-C]. We have adopted a multiplier of [C-I-C] because our research indicates that glass and porcelain insulators cost [C-I-C] more compared to polymeric insulators.

Table 9-3: Weighted average unit rate calculation for insulators

Description	Quantity	Weight	Unit rate ($2019-20)	Unit rate ($2018-19)
500 kV strain insulator replacement with new 500 kV composite strain insulator	10 towers	0.8%	[C-I-C]	[C-I-C]
500 kV V-string suspension insulator replacement with new 500 kV composite suspension insulator	10 towers	0.8%	[C-I-C]	[C-I-C]
500 kV I-string suspension insulator replacement with new 500 kV composite suspension insulator	500 towers	39.1%	[C-I-C]	[C-I-C]
220 kV strain insulator replacement with new 220 kV composite strain insulator	10 towers	0.8%	[C-I-C]	[C-I-C]
220 kV I-string suspension insulator replacement with new 220 kV composite suspension insulator	750 towers	58.6%	[C-I-C]	[C-I-C]
Weighted average unit rate			[C-I-C]	[C-I-C]

Source: AusNet Services

Instrument transformers

We have different types of instrument transformers installed across our transmission network, the cost of which varies according to the type. Table 9-4 sets out our proposed unit rates. To derive our proposed unit rates, we converted the replacement rates in Appendix 4A Unit Rates of this Revenue Proposal into 3 phase and single-phase unit rates. We then multiplied each unit rate by their respective proportion on our transmission network, then added in capitalised overhead,[109] to derive the set of weighted average unit rates shown in Table 9-4.

As a result, our proposed unit rates are consistent with the rates used to derive our capex program contained in Chapter 4 of this Revenue Proposal.[110]

Table 9-4: Unit rates for instrument transformers

Type	Voltage levels	Unit rate ($2018-19)
VTs	< = 33 kV	[C-I-C]
	> 33 kV & < = 66 kV	[C-I-C]
	> 66 kV & < = 132 kV	[C-I-C]
	> 132 kV & < = 275 kV	[C-I-C]
	> 275 kV & < = 330 kV	[C-I-C]
	> 330 kV & < = 500 kV	[C-I-C]
	> 500 kV	[C-I-C]
CTs	< = 33 kV	[C-I-C]
	> 33 kV & < = 66 kV	[C-I-C]
	> 66 kV & < = 132 kV	[C-I-C]
	> 132 kV & < = 275 kV	[C-I-C]
	> 275 kV & < = 330 kV	[C-I-C]

[109] We have applied an overhead rate of 6.2%, which reflects our average actual/expected overheads in the current regulatory period

[110] The unit rates in Appendix 4A Unit Rates are in 2019-20 dollars.

Type	Voltage levels	Unit rate ($2018-19)
	> 330 kV & < = 500 kV	[C-I-C]
	> 500 kV	[C-I-C]

Source: AusNet Services

9.7 Decommissioned insulators and instrument transformers

Our analysis shows that we have decommissioned some insulators and instrument transformers before their end of current standard lives, for reasons such as asset failure and condition. These assets are no longer in service. As a result, these assets have a residual value, but their remaining economic life is zero.

To be consistent with clause 6A.6.3(b)(1), we must depreciate the residual values as quickly as possible. We have calculated the residual values for each asset class, then transferred the residual values from their parent asset classes into new asset classes. We propose to fully depreciate the residual value of these assets (as at 1 April 2022) in 2022-23.

The alternative approach to accelerated depreciation is to allow customers to fund the depreciation over the remaining standard lives of the assets. However, this would mean that future generations continue to pay for assets that are no longer providing transmission services while, at the same time, also paying for the new assets that have replaced them.

The sections below set out our proposed straight-line depreciation allowance and the assumptions that underpin it.

9.7.1 Insulators

Using our valuation model, we estimate the residual value of decommissioned insulators to be $8 million. We propose to fully depreciate the residual value in 2022-23, as set out in Table 9-5.

Table 9-5: Straight-line depreciation of decommissioned insulators ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Insulators	8.4	0.0	0.0	0.0	0.0	8.4

Source: AusNet Services

Below is a brief description of the steps and assumptions that went into calculating the residual value.

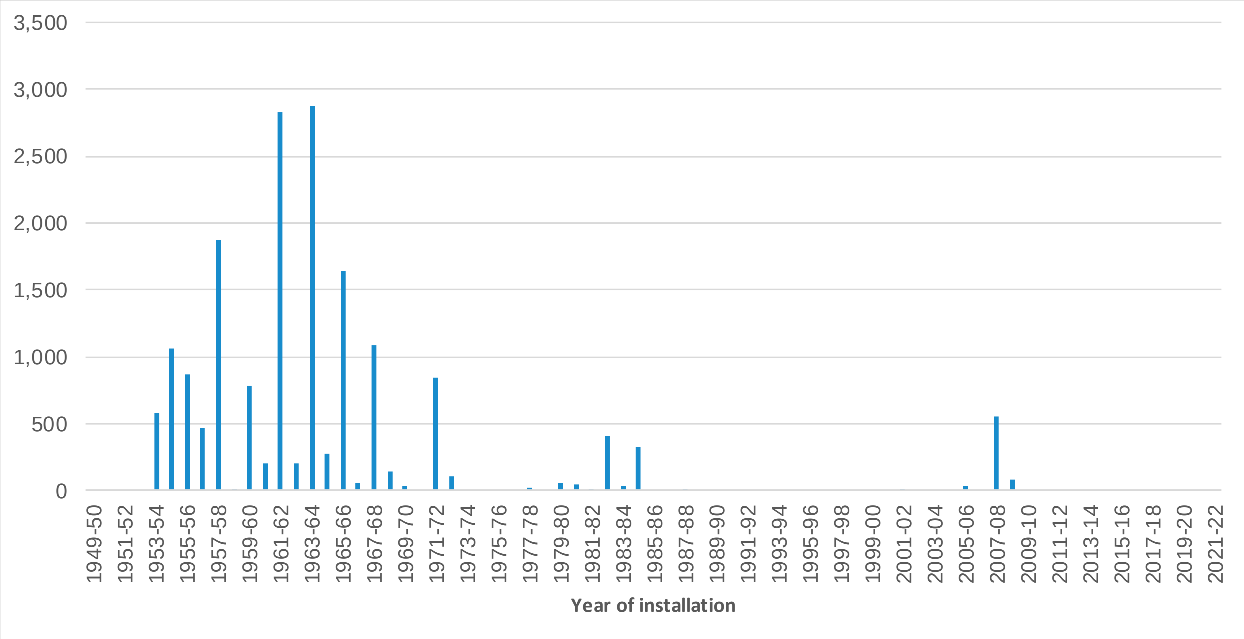
9.7.1.1 Step 1 – establish the total asset population as at 1 April 2022

We estimate that we have decommissioned 17,480 insulators over the past 15 years. We have sourced our data from MAXIMO 5, SAP and individual replacement projects.

9.7.1.2 Step 2 – estimate the historical annual additions to the RAB

We estimated our historical annual additions to the RAB using the data as described in section 9.7.1.1. Our decommissioned volumes are depicted in Figure 9-1.

Figure 9-1: Profile of decommissioned insulators



Source: AusNet Services

9.7.1.3 Step 3 – apply the current unit replacement cost including capitalised overheads

We have applied a unit rate of [C-I-C], calculated using the methodology described in section 9.6.

9.7.1.4 Step 4 – estimate the nominal capex up to 2022

Using the results from step 3, we estimated the nominal capex values for each year.

9.7.1.5 Step 5 – apply a nominal RAB roll forward approach to 1 April 2022

We applied the nominal RAB roll forward approach described in section 9.5.

Instrument transformers

Using our valuation model, we estimate the residual value of decommissioned instrument transformers to be $13 million. We propose to fully depreciate the residual value in 2022-23, as set out in Table 9-6.

Table 9-6: Straight-line depreciation of decommissioned instrument transformers ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Instrument transformers	13.1	0.0	0.0	0.0	0.0	13.1

Source: AusNet Services

Below is a brief description of the steps and assumptions that went into calculating the residual value.

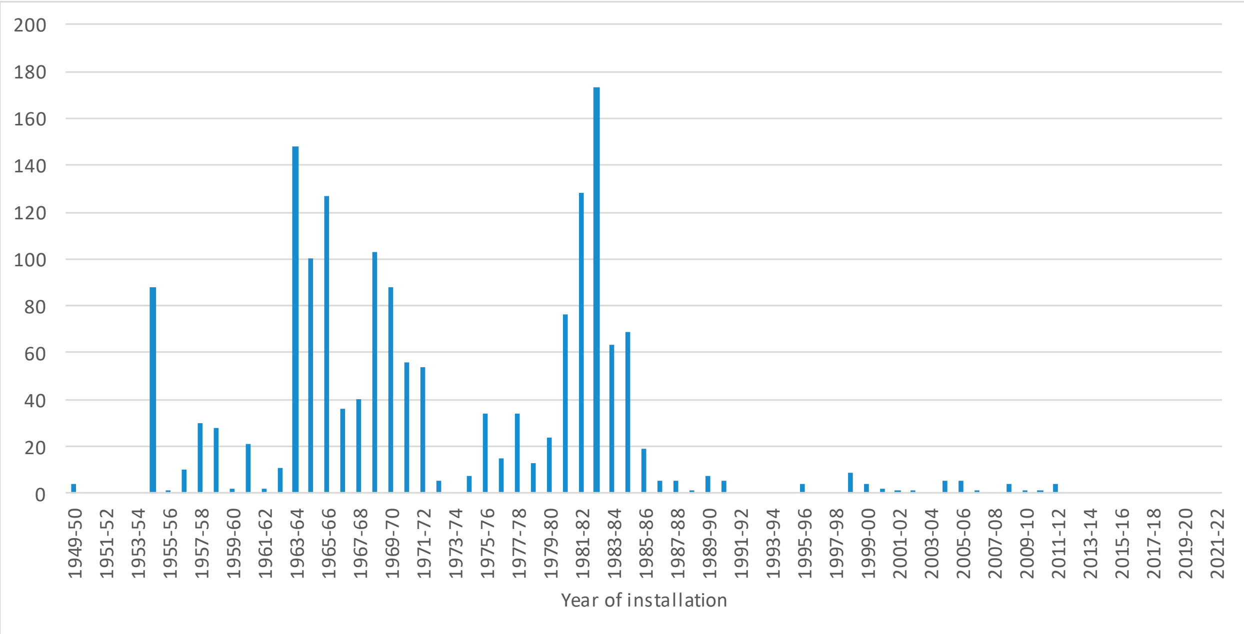
9.7.1.6 Step 1 – establish the total population of the asset as at 1 April 2022

We estimate that we have decommissioned 1,674 instrument transformers over the past 15 years. We have sourced our data from SAP and MAXIMO 5.

9.7.1.7 Step 2 – estimate the historical annual additions to the RAB

We estimated our historical annual additions to the RAB using the data described in section 9.7.1.6.

Figure 9-2: Profile of decommissioned instrument transformers



Source: AusNet Services

9.7.1.8 Step 3 – apply the current unit replacement cost including capitalised overheads

We applied the unit rates described in section 9.6.

9.7.1.9 Step 4 – estimate the nominal capex up to 2022

Using the results from step 3, we estimated the nominal values for each year.

9.7.1.10 Step 5 – apply a nominal RAB roll forward approach to 1 April 2022

We applied a nominal RAB roll forward approach as described in section 9.5.

9.8 Planned decommissioning of insulators and instrument transformers

We plan on decommissioning some insulators and instrument transformers over the 2023-27 regulatory control period, prior to the end of their current standard asset lives.

We will install a new insulator for each insulator decommissioned, i.e. there will be a one-for-one replacement. Conversely, the majority (not all) of the decommissioned instrument transformers will be replaced. This is because some instrument transformers will become integrated, and therefore no longer separately identified.

As the decommissioned assets will no longer be in-service on our transmission network, we propose to fully depreciate these assets by the end of the 2023-27 regulatory control period. Specifically, we have applied straight-line depreciation using a remaining asset life of 5 years.

Ideally, we would fully depreciate these assets the year after they are decommissioned, to reflect the economic lives of those assets. However, we have not done this, as it would be time-consuming to edit the AER's PTRM (version 4) to allow for this functionality. Additionally, the X-factor used to calculate our smoothed revenue requirement would effectively smooth out any lumpiness in the allowance, which means the difference between adopting straight-line depreciation and a more accurate profile, is minimal.

This pragmatic approach reflects the economic lives of those assets, and as a result, is consistent with clause 6A.6.3(b)(1) of the NER.

The alternative approach, wherein customers continue to fund the depreciation over the remaining standard lives of the assets, would mean that future generations pay for assets that are no longer providing transmission services while, at the same time, also paying for the new assets that have replaced them.

Insulators

Using our valuation model, we estimate that the residual value of insulators to be decommissioned over the 2023-27 regulatory control period to be $3 million. We propose to fully depreciate the residual value as set out in Table 9-7.

Table 9-7: Straight-line depreciation of insulators planned for decommissioning ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Insulators	0.6	0.6	0.6	0.6	0.6	2.9

Source: AusNet Services

Below is a brief description of the steps and assumptions that went into calculating the residual value.

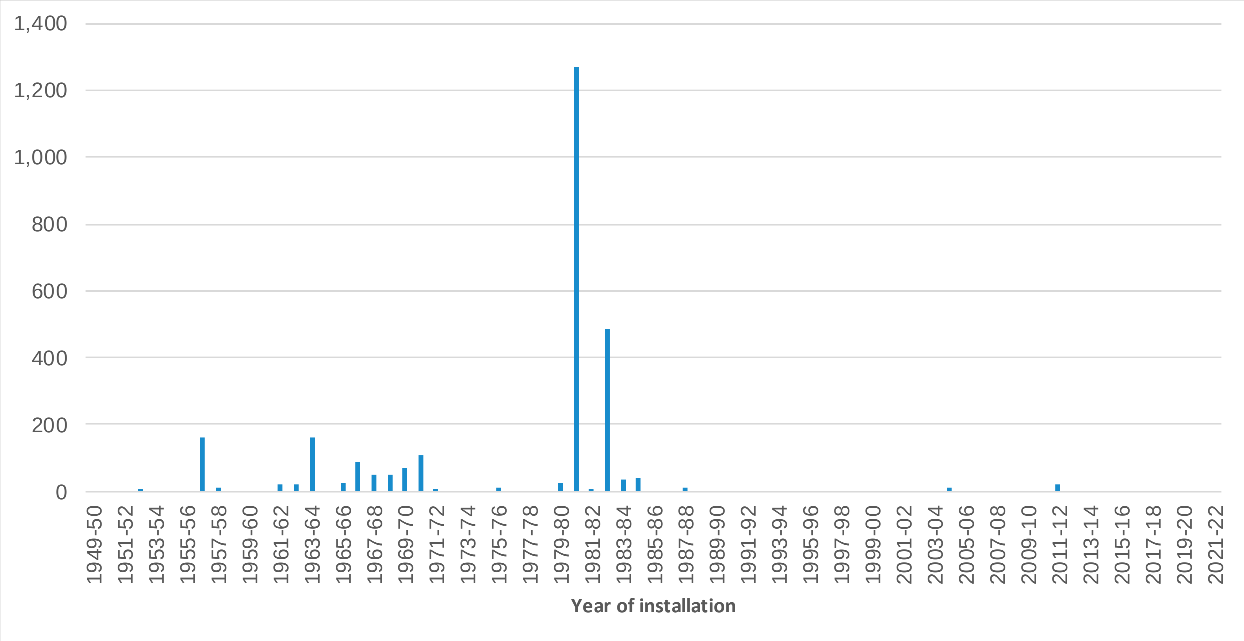
9.8.1.1 Step 1 – establish the total population of the asset as at 1 April 2022

Over the 2023-27 regulatory control period, we estimate that we will decommission 2,682 insulators.

9.8.1.2 Step 2 – estimate the historical annual additions to the RAB

We have estimated our historical annual additions to the RAB due to those assets planned for decommissioning over the 2023-27 regulatory period. See Figure 9-3.

Figure 9-3: Profile of insulators to be decommissioned over the 2023-27 regulatory period



Source: AusNet Services

9.8.1.3 Step 3 – apply the current unit replacement cost including capitalised overheads

We have applied a unit rate of [C-I-C], calculated using the methodology described in section 9.6.

9.8.1.4 Step 4 – estimate the nominal capex up to 2022

Using the results from step 3, we estimated the nominal values for each year.

9.8.1.5 Step 5 – apply a nominal RAB roll forward approach to 1 April 2022

We applied a nominal RAB roll forward approach as described in section 9.5.

Instrument transformers

Using our valuation model, we estimate that the residual value of instrument transformers to be decommissioned over the 2023-27 regulatory control period to be $4 million. We propose to fully depreciate the residual value as set out in Table 9-8.

Table 9-8: Straight-line depreciation of instrument transformers planned for decommissioning ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Instrument transformers	0.9	0.9	0.9	0.9	0.9	4.4

Source: AusNet Services

Below is a brief description of the steps and assumptions that went into calculating the residual value.

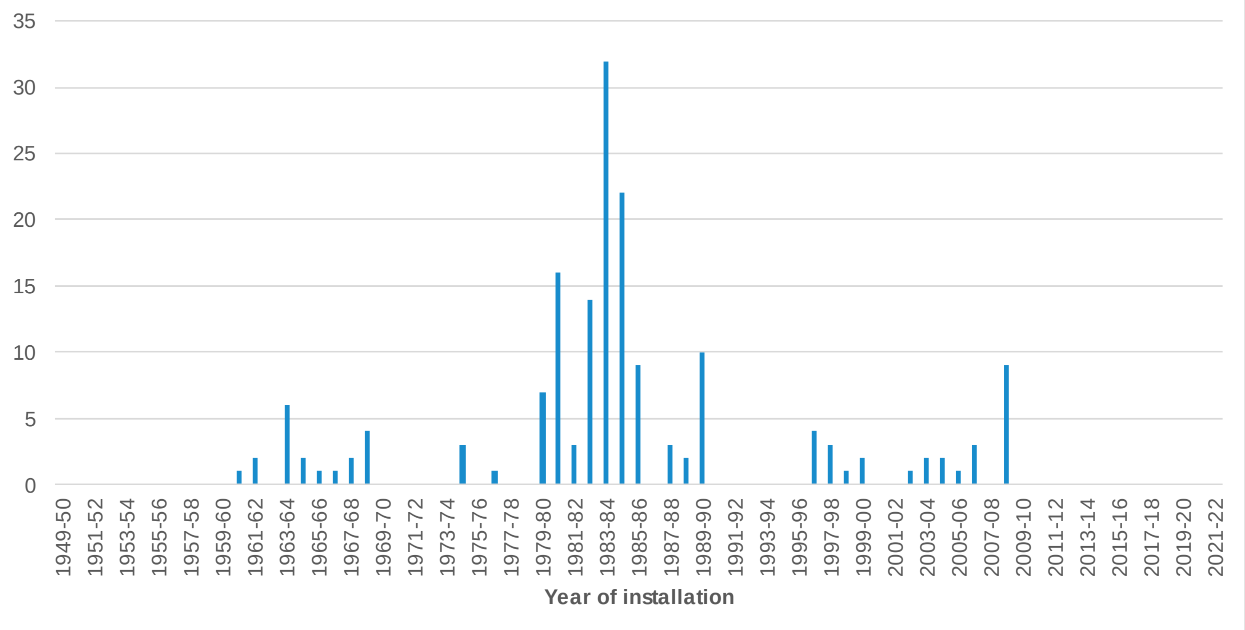
9.8.1.6 Step 1 – establish the total population of the asset as at 1 April 2022

Over the 2023-27 regulatory control period, we estimate that we will decommission 169 instrument transformers.

9.8.1.7 Step 2 – estimate the historical annual additions to the RAB

We have estimated our historical annual additions to the RAB due to those assets planned for decommissioning over the 2023-27 regulatory period, as depicted in Figure 9-4.

Figure 9-4: Profile of instrument transformers to be decommissioned over the 2023-27 regulatory period



Source: AusNet Services

9.8.1.8 Step 3 – apply the current unit replacement cost including capitalised overheads

We have applied the unit rates as described in section 9.6.

9.8.1.9 Step 4 – estimate the nominal capex up to 2022

Using the results from step 3, we estimated the nominal values for each year.

9.8.1.10 Step 5 – apply a nominal RAB roll forward approach to 1 April 2022

We applied the nominal RAB roll forward approach described in section 9.5.

9.9 In-service insulators and instrument transformers

This section discusses our depreciation proposal for the balance of insulators and instrument transformers that are in-service (i.e. excluding the assets described in section 9.7 and 9.8).

In the absence of a disaggregated RAB that separately identifies insulators and instrument transformers, we have had to estimate the residual value of these assets, and then transfer these assets from their parent asset classes into new asset classes.

We then applied an appropriate RAB roll forward approach to estimate the opening asset value for these assets as at 1 April 2022. This allowed us to identify insulators and instrument transformers that are in-service separately from the rest of the RAB, and then depreciate the assets according to a remaining asset life that reflects its economic life. This approach is consistent with clause 6A.6.3(b)(1) of the NER.

Our approach is also similar to the methodology we adopted for the EDPR 2021-26 proposal submitted in January 2020. The AER's Draft Decision considers this to be a reasonable approach.[111]

The following sections describe our reasonings and methodologies for proposing a depreciation allowance that reflects the assets' economic lives and not standard asset lives. For each of the assets (insulators and instrument transformers), we have described:

- Its historical standard asset life;
- Its history and background;
- Our justification for the revised economic life; and
- Our residual value calculation.

Insulators

9.9.1.1 Historical standard asset life

Historically, we have applied a standard asset life of 60 years to insulators because it is a component of its parent asset 'towers and conductors'. The AER approved this approach for the current regulatory control period.

9.9.1.2 History and background

We have approximately 90,000 insulators in-service on the transmission network. Most insulators comprised a number of linked discs made from either porcelain or glass with steel pins to form a continuous string. There are a growing number of polymeric insulators in operation which consist of composite polymer material that has a fibreglass core with a sheath made from silicone rubber or ethylene propylene diene monomer (EPDM).

In 2006, AusNet Services began a large program of targeted insulator replacements. This program commenced in response to increasing trends in insulator functional failures in the period between 2000 and 2007.

In order to maintain the performance and reliability attained in recent years, we have further implemented a selective replacement program.

Some of our high-level strategies for insulators are:

- For new assets, to install polymeric insulators as part of insulator replacement programs;
- For maintenance, replace defective insulators as part of corrective maintenance tasks. Complete string replacement is preferred as it is more economical and safer than the replacing an individual disc from within a string of insulator discs.

Advances in polymer manufacturing have triggered an increase in use of polymeric composite types over the last 15 years. We estimate that approximately 28% of all our insulators are now polymeric.

Polymeric composite types are better than porcelain, glass and mixed type because:

- They are lighter, and lighter material brings about safer outcomes with respect to manual handling;
- Lighter material results in higher productivity when insulators are being replaced;

[111] AER 2020, *AusNet Services Distribution Determination 2021 to 2026, Attachment 4 Regulatory depreciation, Draft Decision*, September, p. 4-13.

- The pollution resistant material that forms the polymeric sheath doesn't require regular washing; and
- It doesn't have the same issue with regards to corrosion and pollution.

Unlike the early versions of polymeric insulators, the current generation of polymeric insulators are resistant to UV degradation. Also, polymer insulators are hydrophobic, meaning water runs off them and does not form a layer which can cause tracking and outages.

Further information on our asset management approach for insulators can be found in our Plant Strategy Document (Transmission Line Insulators).

9.9.1.3 Justification for the revised economic life

Historically, we have applied a standard asset life of 60 years to insulators, because it has always been identified as a component of its parent asset 'towers and conductors'. While 60 years remains appropriate for towers and conductors, it is inappropriate for insulators.

Instead, we propose an economic life of 40 years.

The shorter economic life is based on the average replacement age pertaining to glass, porcelain and polymeric types, weighted by its respective proportion on our transmission network. These weightings are depicted in Table 9-9.

Table 9-9: Weighted average replacement age for insulators

Type	Average replacement age (years)	% of network	Weighted average replacement age (years)
Glass	50	9%	
Porcelain	46	63%	
Polymeric	25	28%	
All		**100%**	**40**

Source: AusNet Services

We have calculated the average replacement age for glass and porcelain insulators by analysing our replacements data over the past 15 years, across all drivers (replacements due to failure, damage and condition). Our analysis is based on over 16,000 replacements. Table 9-10 shows that the average replacement ages for glass and porcelain insulators are 50 years and 46 years respectively.

Table 9-10: Average replacement age for glass and porcelain insulators

Type	Average age of replacement (years)	Count of replacements
Glass	50	11,705
Porcelain	46	5,103

Source: AusNet Services

We have also calculated the average replacement age for polymeric insulators using the same methodology. Our analysis showed that we have replaced over 600 polymeric insulators at an average age of 11 years (see Table 9-11). However, our uptake of polymeric insulators is a relatively recent development, which means that the polymeric insulators on our network are relatively young and the majority have never been replaced before. Our calculated average replacement age of 11 years is low because, of the polymeric insulators we have replaced, the majority are located in very corrosive environments.

This is not reflective of polymeric insulators in general, and the average service life or replacement life of the other polymeric insulators on our network. Our research indicates that the service life of polymeric insulators is 25 years. As a result, we have adopted 25 years as the average replacement age for polymeric insulators. We consider this to be a better representation of when the other polymeric insulators on our network will need to be replaced.

Table 9-11: Average replacement age for polymeric insulators

Driver	Average age of replacement (years)	Count of replacements
Replacement due to failure	9.5	2
Replacement due to damage	9.4	85
Replacement due to condition	10.8	585
All	10.6	672

Source: AusNet Services

9.9.1.4 Residual value calculation

Our historical investment in insulators began in the 1950s and has included a combination of replacement programs and targeted replacements. For this reason, and the time span involved, our historical cost and volume data on a project by project basis is not readily available. Therefore, an estimate of its value must be derived from the best available data. This issue is not unique to insulators, it applies to all asset types.

We have used our valuation model to estimate the residual value of in-service insulators (see section 9.5).

9.9.1.4.1 Step 1 – establish the total population of the asset as at 1 April 2022

We forecast that we will have approximately 90,037 in-service insulators on our transmission network as at 1 April 2022. Our forecast is based on our asset age profile data.

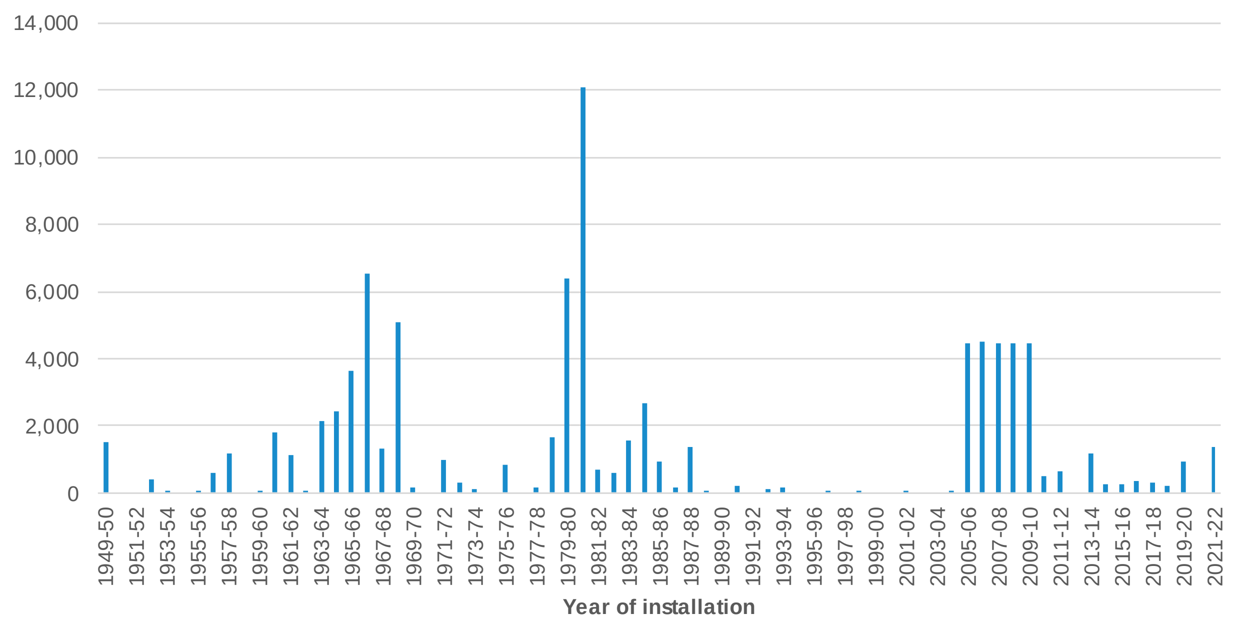
However, as this section of the Revenue Proposal relates to the balance of insulators, excluding those that will be decommissioned over the 2023-27 regulatory period, it is necessary to net off those that will be decommissioned from the network. As a result, the total population of the 'balance' is 87,355 insulators.[112]

9.9.1.4.2 Step 2 – estimate the historical annual additions to the RAB

We have estimated our historical annual additions to the RAB using our asset age profile data, which is represented in Figure 9-5.

[112] 90,037 minus 2,682.

Figure 9-5: Profile of the balance of in-service insulators



Source: AusNet Services

9.9.1.4.3 Step 3 – apply the current unit replacement cost including capitalised overheads

We have applied a unit rate of [C-I-C], calculated in accordance with section 9.6.

9.9.1.4.4 Step 4 – estimate the nominal capex up to 2022

Using the results from step 3, we estimated the nominal values for each year.

9.9.1.4.5 Step 5 – apply a nominal RAB roll forward approach to 1 April 2022

We applied the nominal RAB roll forward approach described in section 9.5.

9.9.1.4.6 Results

Using the methodology described above, we propose an opening RAB value of $168 million as at 1 April 2022. We have therefore removed $168 million from parent asset class 'towers and conductors' and transferred this value into a new asset class.

The revised remaining asset life is now 18.1 years. The revised remaining asset life is the existing remaining asset life as at 1 April 2022 (38.1 years), minus the difference between the current asset life (60 years) and the revised economic life (40 years).

The depreciation profile we proposed over the 2023-27 regulatory control period is outlined in Table 9-12.

Our proposal is consistent with clause 6A.6.3(b)(1) of the NER because it reflects the economic life of insulators. Our proposal is also consistent with clause 6A.6.3(b)(3) because we have proposed a revised economic life of 40 years to apply on a prospective basis, i.e. from 1 April 2022.

Table 9-12: Straight-line depreciation of the balance of in-service insulators ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Insulators	9.2	9.2	9.2	9.2	9.2	46.2

Source: AusNet Services

Instrument transformers

9.9.1.5 Historical standard asset life

Historically, we have applied a standard asset life of 45 years for instrument transformers because it is a component of its parent asset, 'Switchgear'. The AER approved this approach for the current 2018-22 regulatory control period.

9.9.1.6 History and background

Instrument transformers provide accurate measurements of the operating voltages and currents necessary for the safe, reliable and economic protection and control of our transmission network and its interconnections with the NEM.

The majority of our instrument transformers in-service are still an oil-insulated porcelain-housed construction. However, since 2005 there has been a transition to polymer housings. By 2007, all current transformers were purchased with polymer housings, and from 2012, capacitor voltage transformer and medium voltage transformers have also been produced with polymer housings.

Since 2005, we have decommissioned a significant number of current transformers and voltage transformers as part of major asset replacement projects and smaller projects focussed on managing specific supply risks to consumers, safety risks to workers and collateral plant damage risks within terminal stations. These replacement programs have prevented explosive failures and reduced the average service age of current transformers and voltage transformers.

9.9.1.7 Justification for the revised economic life

Historically, we have applied a standard asset life of 45 years for instrument transformers, because it has always been identified as a component of its parent asset, 'Switchgear'. While 45 years might be appropriate for switchgear, it over-estimates the life of instrument transformers.

Instead, we propose an economic life of 38 years. This corresponds to the average replacement age for instrument transformers on our transmission network. Our conclusion is based on an analysis of our SAP and MAXIMO 5 data over the past 15 years. See Table 9-13.

Table 9-13: Average replacement age for instrument transformers

	Average age of replacement (years)	Count of replacements
Instrument transformers	38	1,628

Source: AusNet Services

9.9.1.8 Residual value calculation

Our historical investment in instrument transformers began in the 1950s as the Victorian transmission system was developed. As these assets have reached their end of lives, our capex has included a combination of replacement programs and targeted replacements. For this reason, and the length of time involved, our historical cost and volume data on a project by project basis is not complete. Therefore, we derived an estimate of its value from the best data available. This issue is not unique to instrument transformers, it applies to all asset types.

We used our valuation model to estimate the residual value of in-service instrument transformers, as explained in section 9.5.

9.9.1.8.1 Step 1 – establish the total population of the asset as at 1 April 2022

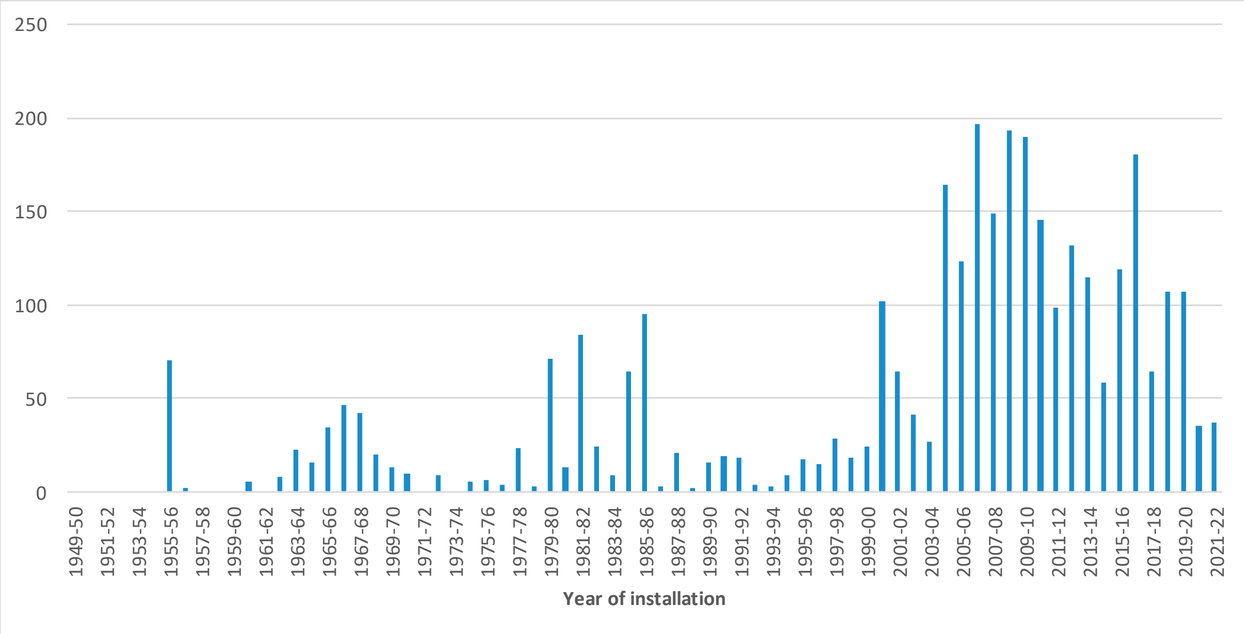
We forecast that we will have approximately 3,511 instrument transformers on our transmission network as at 1 April 2022. Our forecast is based on our asset age profile data.

However, as the analysis in this section relates to the balance of instrument transformers, it is necessary to net off those that will be decommissioned from the network during the 2023-27 regulatory control period. After doing so, the total population of the balance is 3,342 instrument transformers.[113]

9.9.1.8.2 Step 2 – estimate the historical annual additions to the RAB

We estimated our historical annual additions to the RAB using our asset age profile data.

Figure 9-6: Profile of the balance of in-service instrument transformers



Source: AusNet Services

9.9.1.8.3 Step 3 – apply the current unit replacement cost including capitalised overheads

We applied the unit rates described in section 9.6.

9.9.1.8.4 Step 4 – estimate the nominal capex up to 2022

Using the results from step 3, we estimated the nominal values for each year.

9.9.1.8.5 Step 5 – apply a nominal RAB roll forward approach to 1 April 2022

We applied the nominal RAB roll forward approach described in section 9.5.

9.9.1.8.6 Results

Using our methodology described above, we propose an opening RAB value of $275 million as at 1 April 2022. We have therefore removed $275 million from its parent asset class, 'Switchgear', and transferred this value to a new asset class.

The revised remaining asset life is now 26.1 years. This is the existing remaining asset life as at 1 April 2022 (33.4 years), minus the difference between the current asset life (45 years) and the revised economic life of 38 years.

We propose a depreciation profile over the 2023-27 regulatory period as outlined in Table 9-4.

[113] 3,511 minus 169.

Our proposal is consistent with clause 6A.6.3(b)(1) of the NER because it reflects the economic life of instrument transformers. Our proposal is also consistent with clause 6A.6.3(b)(3) because we have proposed a revised economic life of 38 years to apply on a prospective basis i.e. from 1 April 2022 onwards.

Table 9-14: Straight-line depreciation of the balance of in-service instrument transformers ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Instrument transformers	10.5	10.5	10.5	10.5	10.5	52.6

Source: AusNet Services

9.10 Balance of assets in the opening RAB (no accelerated depreciation)

We propose a straight-line depreciation profile over the 2023-27 regulatory control period as outlined in Table 9-15. The depreciation profile excludes the assets for which we have proposed accelerated depreciation (as described in sections 9.7, 9.8 and 9.9 of this Revenue Proposal). Chapter 8 of this Revenue Proposal contains more information about the calculation and roll forward of the RAB.

Table 9-15: Straight-line depreciation of the opening RAB excluding accelerated depreciation ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Existing assets	143.2	140.4	136.4	135.1	130.4	685.5

Source: AusNet Services

Except for the asset classes that we proposing to apply accelerated depreciation to, the remaining lives for existing assets in the RAB are consistent with the asset lives approved for the current regulatory control period.

9.11 New insulators and instrument transformers in the capex program

Based on our proposed capex program of $29 million for insulators and $9 million for instrument transformers, we propose a depreciation profile over the 2023-27 regulatory control period as set out in Table 9-16. Chapter 4 explains our capex program for the next regulatory period.

As explained in section 9.9, our proposal is based on economic lives of 40 years for insulators, and 38 years for instrument transformers.

Table 9-16: Straight-line depreciation of new insulators and instrument transformers ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Insulators	0.0	0.1	0.3	0.4	0.6	**1.4**
Instrument transformers	0.0	0.0	0.1	0.1	0.2	**0.5**
Total	**0.0**	**0.2**	**0.4**	**0.6**	**0.8**	**1.9**

Source: AusNet Services

Table 9-17 presents a summary of our insulators and instrument transformers capex program for the 2023-27 regulatory control period. We note that our proposed funding for insulators is a large component of our proposed safety, security and compliance capex program for the 2023-27 regulatory period. This program is explained in further detail in Chapter 4 of this Revenue Proposal.

Table 9-17: Capex program for insulators and instrument transformers ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Insulators	5.6	5.6	5.7	5.8	6.0	28.7
Instrument transformers	1.7	1.7	1.7	1.8	1.8	8.7

Source: AusNet Services

9.12 Balance of new assets in the capex program (no accelerated depreciation)

We propose a straight-line depreciation profile over the 2023-27 regulatory control period as outlined in Table 9-18. The depreciation profile excludes the assets for which we have proposed accelerated depreciation (insulators and instrument transformers, as described in section 9.11). Chapter 4 of this Revenue Proposal describes our proposed capex program.

Table 9-18: Straight-line depreciation of new capex excluding accelerated depreciation ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
New capex	0.0	6.9	18.5	27.0	35.3	87.8

Source: AusNet Services

Except for insulators, instrument transformers, and capitalised lease assets, the standard asset lives that we have proposed for new capex over the 2023-27 regulatory control period are the same as the standard asset lives approved for the current 2018-22 regulatory period. The standard life for equity raising costs reflects the weighted average life of our total capex over the 2023-27 regulatory period. See Table 9-19.

We have also created five new asset classes in the PTRM that relate to forecast capitalised leasing costs. These capitalised lease costs relate to changes in the Australian accounting standards. Chapter 8 of this Revenue Proposal provides further details on these changes.

Table 9-19: Standard asset lives for new capex

Asset	Standard asset life (years)
Secondary	15.0
Switchgear	45.0
Transformers	45.0
Reactive	40.0
Towers and Conductor	60.0
Establishment	45.0
Communications	15.0
Inventory	n/a
IT	5.0
Vehicles	7.0
other (non-network)	10.0
premises	10.0
Land	n/a
Easements	n/a
Equity raising costs (2003-08)	27.6
Inventory Adjustment (Other non-network)	1.0
Accelerated Depr	0.0

Asset	Standard asset life (years)
Insulators	40.1
Instrument Transformers	37.8

Source: AusNet Services

9.13 A summary of the forecast depreciation allowance

Based on the depreciation methodology described in earlier sections, our total forecast straight-line depreciation for the 2023-27 regulatory control period is 903 million.

Table 9-20: Straight-line depreciation ($M, real 2021-22)

		2022-23	2023-24	2024-25	2025-26	2026-27	Total
Existing assets in the RAB	Insulators decommissioned	8.4	0.0	0.0	0.0	0.0	8.4
	Insulators to be decommissioned over 2023-27 regulatory period	0.6	0.6	0.6	0.6	0.6	2.9
	Balance of insulators	9.2	9.2	9.2	9.2	9.2	46.2
	Instrument transformers decommissioned	13.1	0.0	0.0	0.0	0.0	13.1
	Instrument transformers to be decommissioned over 2023-27 regulatory period	0.9	0.9	0.9	0.9	0.9	4.4
	Balance of instrument transformers	10.5	10.5	10.5	10.5	10.5	52.6
	All other assets	143.2	140.4	136.4	135.1	130.4	685.5
New capex	Insulators	0.0	0.1	0.3	0.4	0.6	1.4
	Instrument transformers	0.0	0.0	0.1	0.1	0.2	0.5
	All other assets	0.0	6.9	18.5	27.0	35.3	87.8
Total straight-line depreciation		**186.0**	**168.7**	**176.5**	**183.9**	**187.7**	**902.8**

Source: AusNet Services

However, to calculate the regulatory depreciation, we must remove the effects of indexation on the RAB. As a result, our total forecast regulatory depreciation for the 2023-27 regulatory period is $545 million, as shown in Table 9-21.

Table 9-21: Summary of our proposed regulatory depreciation ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Straight-line depreciation	190.2	176.4	188.6	201.0	209.8	**966.0**
RAB indexation	-80.5	-82.2	-84.4	-86.4	-87.4	**-420.9**
Regulatory depreciation	**109.6**	**94.2**	**104.3**	**114.6**	**122.4**	**545.1**

Source: AusNet Services

9.14 Supporting documentation

We have provided the following documents in support of this chapter:

- Valuation Models (Insulators and Instrument Transformers);
- Appendix 4A - Unit Rates;
- Post Tax Revenue Model; and

- Roll Forward Model.

10 Return on capital and gamma

10.1 Key points

- In December 2018, the AER published its Rate of Return Instrument[114] and an accompanying explanatory statement.[115] As a binding instrument, the Rate of Return Instrument sets out the key parameter values and the method to be applied in estimating the rate of return.
- Our cost of equity and debt have been estimated in accordance with the AER's Rate of Return Instrument. A gamma value of 0.585 has also been adopted in accordance with the Instrument.
- Our debt and equity raising costs have been estimated in accordance with the AER's current practice.
- Our inflation placeholder of 2.25% for the forthcoming regulatory control period is calculated using the AER's current approach to estimating forecast inflation. We remain concerned that the AER's current approach to inflation is not appropriate, and we welcome the outcome of the AER's inflation review which is expected to be concluded by December 2020.

10.2 Chapter structure

The structure of the remainder of this Chapter is:

- Section 10.3 provides a brief commentary on the AER's Rate of Return Instrument;
- Sections 10.4 and 10.5 set out our allowed cost of equity and debt for the 2023-27 regulatory period;
- Section 10.6 summarises our estimated weighted average cost of capital (WACC);
- Sections 10.7 and 10.8 present our estimated equity raising and debt raising costs;
- Section 10.9 recaps the role of imputation credits under the Post Tax Revenue Model (PTRM), and notes the value of gamma adopted for the 2023-27 regulatory control period;
- Section 10.10 explains our approach to forecast inflation, noting that the AER's current approach is subject to review; and
- Section 10.11 lists the supporting documents for this chapter.

10.3 Rate of Return Instrument

In November 2018, the National Electricity Law was amended to require the AER to make a binding rate of return instrument.[116] As a binding instrument, it must set out the precise value for the rate of return, or a method for calculating the rate of return that can be applied automatically without exercise of discretion. The AER published its Rate of Return Instrument and an accompanying explanatory statement in December 2018.[117]

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114 AER, *Rate of Return Instrument, December 2018 (Rate of Return Instrument)*., available at: https://www.aer.gov.au/system/files/2018%20Rate%20of%20Return%20Instrument%20%28Version%201.02%29_1.pdf.

115 AER, *Rate of Return Instrument – Explanatory Statement*, December 2018, available at: https://www.aer.gov.au/system/files/Rate%20of%20Return%20Instrument%20-%20Explanatory%20Statement.pdf.

116 National Electricity Law, Part 3, Division 1B.

117 Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-instrument-2018.

More recently, the AER published its first rate of return annual update, which provides stakeholders with information on rate of return data, particularly time series market data, showing changes since the publication of the 2018 Rate of Return instrument.[118] The next Rate of Return Instrument is to be published in December 2022 and will bind all regulatory determinations in the subsequent four years. This Revenue Proposal, however, will be subject to the 2018 Rate of Return Instrument.

The AER's 2018 Rate of Return Instrument maintains its long-standing regulatory approach of determining a nominal vanilla weighted average return on equity and debt, weighted by the gearing ratio. The AER's Rate of Return Instrument therefore defines the allowed rate of return as follows:

$$k_t = (1-G) \times k^e + k_t^d \times G$$

where:

k_t is the rate of return in regulatory year t;

k^e is the allowed return on equity for the regulatory period and is calculated in accordance with clause 4 of the instrument;

k_t^d is the allowed return on debt for the regulatory year t, and is calculated in accordance with clause 9 of the instrument; and

G is the gearing ratio and is set at a value of 0.6.

In accordance with the NER[119], this chapter sets out our calculation of the allowed rate of return for each regulatory year of the 2023-27 regulatory control period.

10.4 Return on Equity

The AER's explanatory statement adopts the Sharpe-Lintner CAPM (SLCAPM) to calculate the return on equity. Within the SLCAPM formula, the AER sets fixed values for the market risk premium and equity beta and establishes a formula for calculating the risk free rate. Clause 4 of the AER's Rate of Return Instrument defines the return on equity as follows:

$$k^e = k^f + \beta \times MRP$$

where:

k^f is the allowed risk free rate of return expressed as an effective annual rate percentage;

β is the allowed equity beta and is set to a value of 0.6; and

MRP is the allowed market risk premium and is set to a value of 6.1% per annum.

As the values of the equity beta and market risk premium have been set by the AER's Rate of Return Instrument, we have adopted these values for the purpose of this Revenue Proposal in accordance with the requirements of the NER.

The Rate of Return Instrument requires us to estimate the risk free rate using a formula based on yields on 10-year Commonwealth Government Securities (CGS). The formula requires the risk free averaging period to be:

- Over a period of between 20 and 60 business days;
- Start no earlier than 7 months prior to the commencement of the regulatory period; and

118 AER, *Rate of Return Annual Update*, December 2019 – available at: https://www.aer.gov.au/system/files/Rate%20of%20return%20annual%20update%20%E2%80%93%20December%202019.pdf.

119 National Electricity Rules, SA6.1.3(4A).

- Finish no later than 3 months prior to the commencement of the regulatory period.[120]

In accordance with the Rate of Return Instrument, we have nominated our averaging periods in a confidential letter to the AER. For the purpose of this Revenue Proposal, it is only possible to provide an estimate of the risk free rates that will apply in the respective nominated averaging periods. In this Revenue Proposal, we have adopted a risk free rate estimated over 21 consecutive business days ending 30 June 2020, which results in a risk free rate of 0.93%. The AER will update the risk free rates and the resulting cost of equity in its draft and final decisions.

In accordance with the Rate of Return Instrument, our estimated cost of equity for the purpose of this Revenue Proposal is 4.59%, as presented in the table below.

Table 10-1: Proposed cost of equity parameters

Parameter	Proposed value	Basis of parameter value
Risk fee rate (nominal)	0.93%	This is a placeholder value reflecting the yield on ten year Commonwealth bonds measured over the 21 business day period ending 30 June 2020. The risk free rate for the AER's final determination will be measured over the nominated periods selected in accordance with clause 8 of the Rate of Return Instrument.
Equity beta	0.6	This value is consistent with clause 4(b) of the Rate of Return Instrument.
Market risk premium	6.1%	This value is consistent with clause 4(c) of the Rate of Return Instrument.
Cost of equity	4.59%	The cost of equity is estimated in accordance SLCAPM, as specified in clause 4 of the Rate of Return Instrument.

10.5 Cost of debt

The AER explains that its approach to estimating the cost of debt comprises the following key elements:[121]

- A benchmarking approach, based on debt yield data from third party data providers and benchmarks for term of debt and credit rating;
- A 10-year trailing average approach with an annual update; and
- A 10-year transition to the 10-year trailing average approach, noting that where a transition has commenced in a previous determination, the AER will continue that transition.

In its final decision for our 2017-22 regulatory control period, the AER adopted an 'on-the-day' approach for the first regulatory year and commenced a 10-year transition to a trailing average approach, which operates as follows:

- For 2017, the estimated cost of debt reflected the prevailing market rates near the commencement of the 2017-22 regulatory period.

120 AER, *Rate of Return Instrument*, clause 8.

121 Ibid.

- For each subsequent year, 10% of the return on debt is updated to reflect the prevailing market conditions in that year.

In accordance with the Rate of Return Instrument, this transitional approach has been maintained for the forthcoming regulatory control period. For the purpose of this Revenue Proposal, the average placeholder portfolio cost of debt is **4.35**%, incorporating a placeholder prevailing cost of debt of **2.75**%.[122] The return on debt will be updated in accordance with AER's Rate of Return Instrument, reflecting:

- The average of data published by Bloomberg, the Reserve Bank of Australia and Thomson Reuters on the annualized yield on ten year BBB+ rated corporate debt calculated over the nominated averaging period, which will be selected in accordance with paragraphs 23 and 24 of the Rate of Return Instrument; and
- The historic cost of debt allowances over the preceding years, which includes the 'on the day' rate for the 2017-18 regulatory year of 4.94%.

The table below shows the estimated cost of debt over the 2023-27 regulatory control period, in accordance with the AER's preferred transition to the trailing average approach.

Table 10-2: Estimated benchmark cost of debt

	2023	2024	2025	2026	2027
Nominal pre-tax return on debt	4.35%	4.13%	3.91%	3.69%	3.47%

10.6 Nominal vanilla WACC

The table below summarises the calculation of the nominal vanilla WACC or the 'allowed rate of return', in accordance with clause 3 of the Rate of Return Instrument. The table shows that the application of the AER's approach results in a WACC of 4.44% for 2023, reducing to 3.92% by 2027.

Table 10-3: Estimated nominal vanilla WACC

	2023	2024	2025	2026	2027
Return on equity	4.59%	4.59%	4.59%	4.59%	4.59%
Nominal pre-tax return on debt	4.35%	4.13%	3.91%	3.69%	3.47%
Gearing	60%	60%	60%	60%	60%
Nominal vanilla WACC	**4.44%**	**4.31%**	**4.18%**	**4.05%**	**3.92%**

The allowed rate of return will be updated in the AER's draft and final decisions and then annually to reflect movements in the cost of debt.

10.7 Equity raising costs

Equity raising costs are the transaction costs incurred when network service providers raise new equity in order to fund capital investment. Accordingly, the AER provides a benchmark allowance

122 Based on a placeholder averaging period of 28 January 2020 to 14 February 2020.

to reflect the efficient costs of raising equity, if equity raising is required to maintain the benchmark gearing of 60%.

Our equity raising costs are derived from the PTRM and the AER's benchmarking approach, which includes a distribution rate of 0.9, consistent with the Rate of Return Instrument. Our modelling indicates that under the AER's approach no external equity injection is required to maintain the benchmark capital structure over the 2023-27 regulatory control period.

10.8 Debt raising costs

Debt raising costs are transaction costs incurred each time debt is raised or refinanced. These costs may include arrangement fees, legal fees, company credit rating fees and other transaction costs.

The AER provides a benchmark allowance for debt raising costs as a component of our operating expenditure allowance. The AER's approach is based on a report from the Allen Consulting Group, commissioned by the ACCC in 2004.[123] The AER subsequently updated Allen Consulting Group's analysis to reflect more recent market data provided by PricewaterhouseCoopers during the 2013 rate of return guideline process.[124]

We note that the AER is currently reviewing its approach to estimating debt raising costs. In this Revenue Proposal, we have calculated a debt raising cost allowance based on the AER's recent approach to setting benchmark debt raising costs, as set out in the Final Decision for SA Power Networks, published in June 2020. The resulting benchmark allowance is included in our operating expenditure forecasts, which are set out in Chapter 5.

10.9 Imputation Credit Value (Gamma)

Under the Australian imputation tax system, investors receive imputation credits for tax paid at the company level. For eligible shareholders, imputation credits offset their Australian income tax liabilities. The AER takes account of the value of imputation credits (known as gamma or 'γ') to recognise that imputation credits benefit equity holders, in addition to any dividends or capital gains they receive.

As the regulatory framework applies a post-tax WACC, the value of imputation credits is not a WACC parameter. Instead, the value of imputation credits is a direct input into the calculation of a network service provider's benchmark tax allowance. In accordance with the Rate of Return Instrument, we have adopted a value for imputation credits of 0.585.

The calculation of our benchmark tax allowance for the 2023-27 regulatory control period is provided in Chapter 11.

10.10 Forecast inflation

Our forecast inflation placeholder is 2.25% for the 2023-27 regulatory control period. This figure will be updated in the AER's draft and final decisions. This forecast is based on the AER's current approach to estimating the average annual rate of inflation expected over a ten year period, which reflects:

- The RBA's inflation forecasts for the first two years of the relevant regulatory control period, which is the limit of this forecast series; and

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123 Allen Consulting Group, *Debt and Equity Raising Transaction Costs*, December 2004.

124 PWC, *Energy Networks Association: Debt financing costs*, June 2013.

- The mid-point of the RBA's target band for inflation (currently 2.5%) to extend the series out to ten years.

Whilst a placeholder based on the AER’s approach has been applied in this Revenue Proposal, we continue to have significant concerns with the AER’s application of its current methodology to setting expected inflation. Inflation outcomes have been well below the RBA’s target band for more than 5 years. There is no indication that inflation is expected to increase to be within the target range in the near future.

As the AER’s current forecasting approach is heavily weighted to deliver the mid-point of the RBA’s target band, the current low inflation expectations are not appropriately reflected in the AER’s inflation forecast.

The AER is currently reviewing its approach to setting inflation expectations and AusNet Services is actively participating in this review. We welcome this review, as the current economic environment – comprising sustained low bond rates, exacerbated by COVID-19 – combined with the current approach to setting expected inflation are producing unsustainable outcomes.

We expect that the conclusions of this review, which is due to finish in December 2020, will be applied in the AER’s Draft Decision for this revenue review.

10.11 Supporting documentation

The following documents are provided in support of this chapter:

- Appendix 10A - Averaging Period Letter
- Rate of Return Build up model.

11 Corporate tax allowance

11.1 Key points

The key points in this chapter are:

- The AER has implemented its findings from its recent tax review. This chapter explains the key changes that will affect our business from 1 April 2022 onwards.
- We have maintained the Weighted Average Remaining Life (WARL) approach for depreciating the opening Tax Asset Base (TAB).
- We have explained the basis of our forecast of immediately deductible expenditure for the period 1 April 2022 to 31 March 2027, which is a new requirement under the AER's revised tax approach.

11.2 Chapter structure

This chapter is structured as follows:

- Section 11.3 discusses the AER's regulatory tax approach
- Section 11.4 explains the method for calculating the tax allowance;
- Section 11.5 calculates the opening TAB as at 1 April 2022;
- Sections 11.6 and 11.7 summaries our remaining tax lives and standard tax lives inputs respectively;
- Sections 11.8 and 11.9 present our company income tax rate and value of imputation credits inputs respectively;
- Section 11.10 summarises our forecast of immediately deductible expenditure for the 2023-27 regulatory control period;
- Section 11.11 sets out the proposed tax allowance; and
- Section 11.12 lists the supporting documentation for this chapter.

11.3 AER's regulatory tax approach

The cost of corporate income tax is one component of the AER's building block approach. We are allowed to recover an estimate of the cost of corporate income tax that an efficient transmission business would incur as a result of providing prescribed transmission services.

The AER has reviewed its regulatory tax approach following consultation with the Australian Tax Office (ATO) on the material discrepancy between the tax allowances set by the AER and the actual tax payments made to the ATO by the regulated networks.

As a result of the review, the AER published a new version (version 4) of the Post Tax Revenue Model (PTRM) that implements the recommendations contained in its final report.

Specifically, the AER made two changes which affect the calculation of tax depreciation in the PTRM:

- **Immediate expensing of capex:** allows for inputs of certain capex to be immediately expensed when estimating the benchmark tax expense.

- **Diminishing value depreciation method:** applies diminishing value method for tax depreciation purposes to all new depreciable assets, other than capex associated with in-house software, equity raising costs and buildings which may be depreciated on a straight line basis.

We have populated the latest version of the PTRM (version 4) with the data presented in this Revenue Proposal.

11.4 Method for calculating the tax allowance

11.4.1 Overview

The AER's PTRM calculates a transmission business's tax allowance (or the tax building block) in accordance with clause 6A.6.4 of the NER. Specifically, the PTRM calculates the tax allowance for each year by:

1. deducting tax expenses (opex, tax depreciation, interest on debt, and relevant revenue adjustments) from the revenue requirement to arrive at the TNSP's taxable income; and
2. multiplying taxable income by the corporate income tax rate, then multiplying the result by one minus the value of imputation credits (gamma).

This calculation is represented by the following equation in clause 6A.6.4 of the NER:

$$ETC_t = (ETI_t \times r_t)\ (1 - \gamma)$$

where:

ETI_t is an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of prescribed transmission services if such an entity, rather than the Transmission Network Service Provider, operated the business of the Transmission Network Service Provider, such estimate being determined in accordance with the post-tax revenue model;

r_t is the expected statutory income tax rate for that regulatory year as determined by the AER; and

γ is the allowed imputation credits for the Transmission Network Service Provider for the regulatory year.

11.4.2 Inputs to the calculation of the tax allowance

The method for calculating our tax allowance for the 2023-27 regulatory control period requires the following inputs:

- Opening TAB as at 1 April 2022;
- Remaining tax lives;
- Standard tax lives;
- The company income tax rate;
- The value of imputation credits (gamma); and
- A forecast of immediate expensed (for tax purposes) capex for the 2023-27 regulatory period.

Each of these inputs is discussed in turn in the following sections.

11.5 Opening tax asset base as at 1 April 2022

We have used a combination of actual and forecast net capex and straight-line depreciation to roll forward our TAB. Table 11-1 presents our proposed TAB roll forward to 1 April 2022.

We note that our net capex values for 2020-21 and 2021-22 are forecasts only. Our Revised Revenue Proposal will update these forecasts for any actual capex data that becomes available.

We have adopted the WARL approach, which means our straight-line depreciation figures are based on the remaining tax lives contained in our submitted PTRM. See section 11.6 for more information on our remaining tax lives.

Table 11-1: Tax asset base roll forward ($M, nominal)

	2017-18	2018-19	2019-20	2020-21	2021-22
Opening TAB	2,418.2	2,403.1	2,392.3	2,491.4	2,593.1
Capex net of disposals	105.0	116.0	221.9	228.0	144.9
Straight-line depreciation	-120.1	-126.9	-122.8	-126.3	-138.4
Final year asset adjustments	-	-	-	-	244.0
Closing TAB	**2,403.1**	**2,392.3**	**2,491.4**	**2,593.1**	**2,843.6**

Source: AusNet Services

Our proposed TAB roll forward also reflects the following:

- Our final year adjustments as described in section 11.5.1; and
- Our opening TAB values for insulators and instrument transformers as described in section 11.5.2.

11.5.1 Final year asset adjustments

We have also proposed several end of period asset adjustments to the TAB. These adjustments primarily relate to the depreciation of insulators and instrument transformers over a period that reflects their economic lives, and the roll-in of growth assets.[125] Chapter 8 sets out the background to these adjustments. Table 11-2 describes our proposed final year asset adjustments to the TAB.

Table 11-2: Final year asset adjustments

	Proposed TAB adjustments ($M, nominal)			Remaining life of adjustments to TAB (years)
	Growth assets	Others	All	All
Secondary	23.1	-	23.1	7.6
Switchgear	58.3	-177.1	-118.7	12.9
Transformers	50.1	-	50.1	34.8
Reactive	11.0	-	11.0	34.7
Towers and Conductor	62.9	-114.7	-51.7	1.1
Establishment	36.0	-	36.0	34.6

[125] Previously known as Group 3 assets.

	Proposed TAB adjustments ($M, nominal)			Remaining life of adjustments to TAB (years)
	Growth assets	Others	All	All
Communications	0.3	-	0.3	7.2
other (non-network)	2.2	-	2.2	4.2
Insulators - Already Decommissioned	-	7.6	7.6	1.0
Insulators - Decommission 2023-2027	-	2.2	2.2	5.0
Insulators	-	104.8	104.8	18.1
Instrument Transformers - Already Decommissioned	-	14.7	14.7	1.0
Instrument Transformers - Decommission 2023-2027	-	3.9	3.9	5.0
Instrument Transformers	-	158.5	158.5	26.1
Total	**244.0**	**-**	**244.0**	

Source: AusNet Services

11.5.2 Opening TAB values for new asset classes

Table 11-3 presents our opening TAB for new asset classes.[126]

We estimated the opening value in the sunk tax asset base for insulators and instrument transformers, at 1 April 2022. As discussed in Chapter 8, we propose to transfer these assets from their existing asset classes to new asset classes. These transfers are reflected in the forecast final year asset adjustments section of our RAB roll forward model.

Table 11-3: Estimated opening TAB for new asset classes

Asset type	Estimated opening TAB ($M, nominal)	Average remaining life (years)
Insulators - Already Decommissioned	7.6	1.0
Insulators - Decommission 2023-2027	2.2	5.0
Insulators	104.8	18.1
Instrument Transformers - Already Decommissioned	14.7	1.0
Instrument Transformers - Decommission 2023-2027	3.9	5.0
Instrument Transformers	158.5	26.1
Lease L&B 2019-20 < 20 years rem life	19.6	8.1
Lease L&B 2019-20 > 20 years rem life	19.1	46.0
Lease L&B 2020-21	7.6	9.7

Source: AusNet Services

[126] These asset classes are new compared to the current period.

We have estimated the opening TAB for insulators and instrument transformers, as at 1 April 2022, by:

- Calculating the RAB proportions for insulators and instrument transformers, as a percentage of their parent asset classes (as at 1 April 2017). We sourced the opening RAB for insulators and instrument transformers from our Accelerated Depreciation Model. We sourced the opening RAB of their parent asset classes from the final model approved by the AER in its transmission determination for the current regulatory control period.
- Multiplying the proportions above, by the opening TAB as at 1 April 2017, to estimate the opening TAB for insulators and instrument transformers as at 1 April 2017. We sourced the opening TAB from the AER's final approved model.
- Rolling forward the opening RAB as at 1 April 2017 to 1 April 2022.

We determined the opening TAB for capitalised lease assets as at 1 April 2022, by sourcing and adjusting for:

- Actual net capex;
- Actual tax depreciation; and
- Final year adjustments.

11.6 Remaining tax lives

Table 11-4 presents our remaining tax lives as at 1 April 2022, for asset classes that also exist under the current regulatory control period.

Table 11-4: Remaining tax lives for existing asset classes

Asset type	Remaining life (years)
Secondary	8.1
Switchgear	32.3
Transformers	28.6
Reactive	24.0
Towers and Conductor	24.8
Establishment	31.1
Communications	9.2
Inventory	n/a
IT	2.7
Vehicles	6.5
other (non-network)	5.3
premises	17.2
Land	n/a
Easements	n/a
Equity raising costs (2003-08)	-
Inventory Adjustment (Other non-network)	-
Accelerated Depr	-

Source: AusNet Services

Due to our proposal to depreciate some assets according to their economic lives (rather than the current standard asset lives), we have created 6 new asset classes. Table 11-5 sets out the remaining tax lives for the new asset classes as at 1 April 2022.

Table 11-5: Remaining tax lives for new asset classes

Asset class	Remaining life (years)
Insulators - Already Decommissioned	1.0
Insulators - Decommission 2023-2027	5.0
Insulators	18.1
Instrument Transformers - Already Decommissioned	1.0
Instrument Transformers - Decommission 2023-2027	5.0
Instrument Transformers	26.1

Source: AusNet Services

11.7 Standard tax lives

The standard tax lives that we have proposed for new capex over the 2023-27 regulatory control period are consistent with the standard tax lives for the current 2018-22 regulatory period (see Table 11-6). Our standard tax lives also reflect the tax lives contained in the ATO's latest tax ruling (TR 2020/3) with the exception of insulators, instrument transformers, and capitalised leasing assets which align with their respective proposed standard RAB lives.

Table 11-6: Standard tax lives for new capex

Asset type	Proposed standard tax life (years)	DV rate
Secondary	12.5	16%
Switchgear	40.0	5%
Transformers	40.0	5%
Reactive	40.0	5%
Towers and Conductor	47.5	4%
Establishment	40.0	5%
Communications	12.5	16%
Inventory	n/a	n/a
IT	3.5	57%
Vehicles	8.0	25%
other (non-network)	10.0	20%
premises	20.0	10%
Land	n/a	n/a
Easements	n/a	n/a
Equity raising costs (2003-08)	5.0	40%
Inventory Adjustment (Other non-network)	-	n/a
Insulators	40.1	5%
Instrument Transformers	37.8	5%
Lease L&B 2019-20 < 20 years rem life	10.1	20%
Lease L&B 2019-20 > 20 years rem life	48.0	4%

Asset type	Proposed standard tax life (years)	DV rate
Lease L&B 2020-21	10.7	19%
Lease L&B 2021-22	-	n/a
Lease L&B 2022-23	25.0	8%
Lease L&B 2023-24	19.0	11%
Lease L&B 2024-25	-	n/a
Lease L&B 2025-26	31.8	6%
Lease L&B 2026-27	15.4	13%
Buildings	40.0	5%
In-house software	5.0	40%
Equity raising costs	5.0	40%

Source: AusNet Services

Five of the new asset classes in Table 11-6 above, relate to forecast capitalised leasing costs for the 2023-27 regulatory control period. These capitalised lease costs relate to changes in Australian accounting standards. Further information about these changes are contained in Chapter 8.

The AER created two new asset classes – 'Buildings' and 'In-house software' – to implement the findings of their 2018 Tax Review. The standard tax lives of these assets are 40 years and 5 years respectively, which are consistent with Australian tax law.

11.8 Company income tax rate

In accordance with clause 6A.6.A of the NER, the expected statutory income tax rate is the rate as determined by the AER. The AER's PTRM model defines the company income tax rate as 30%.

11.9 Value of imputation credits (gamma)

The allowed imputation credit is the value stated in the applicable rate of return instrument for the Network Service Provider for the regulatory year. The applicable rate of return instrument is the AER's 2018 rate of return instrument (version 1.02), which states that the value of imputation credits is 58.5%.

11.10 Forecast of immediately deductible expenditure

Table 11-7 contains our forecast of immediately deductible capital expenditure over the 2023–27 regulatory control period.

Table 11-7: Forecast of immediately deductible expenditure ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Secondary	0.4	1.1	0.6	0.8	0.8	**3.7**
Switchgear	0.8	3.6	1.6	2.5	1.6	**10.2**
Transformers	0.4	3.6	1.6	2.5	1.5	**9.5**
Towers and Conductor	0.5	0.7	0.6	0.8	1.0	**3.6**
Establishment	0.4	1.9	0.9	1.4	0.9	**5.4**
Communications	0.9	1.0	1.0	1.2	1.7	**5.8**

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
IT	0.1	0.1	0.1	0.1	0.1	**0.4**
Insulators	0.3	0.3	0.3	0.4	0.5	**1.7**
Instrument Transformers	0.1	0.1	0.1	0.1	0.2	**0.5**
In-house software	0.3	0.3	0.3	0.3	0.3	**1.5**
Total	**4.1**	**12.5**	**6.9**	**10.3**	**8.6**	**42.4**

Source: AusNet Services

Our forecast of immediately deductible capital expenditure is equal to our forecast of capitalised overheads. Since 2018-19, our capitalised overheads have included both labour and non-labour components.

We confirm that we do not intend to change our current tax policy of immediately expensing capital expenditure for our electricity transmission business.

11.11 Summary of tax allowance

Table 11-8 summarises our forecast TAB roll forward for the 2023-27 regulatory control period.

Table 11-8: Tax asset base roll forward ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27
Opening TAB	2,843.6	2,781.1	2,905.6	2,893.7	2,907.6
Net Capex	104.8	290.9	166.0	197.5	128.5
Tax Depreciation	-167.3	-166.4	-177.8	-183.6	-193.4
Closing TAB	**2,781.1**	**2,905.6**	**2,893.7**	**2,907.6**	**2,842.7**

Source: AusNet Services

Based on the various inputs described in earlier sections, we propose the tax allowance over the 2023-27 regulatory control period summarised in Table 11-9. We confirm that, consistent with our final PTRM for the current 2017-22 regulatory control period, we will not have any accumulated tax losses as at 1 April 2022.

Table 11-9: Proposed tax allowance ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Tax payable	2.8	-	-	-	-	**2.8**
Imputation credits	-1.6	-	-	-	-	**-1.6**
Total	**1.1**	**-**	**-**	**-**	**-**	**1.1**

Source: AusNet Services

11.12 Supporting documentation

The following documentation is provided in support of this chapter:

- Opening TAB adjustments model.

12 Cost pass-through

12.1 Key points

The key points of this chapter are:

- A cost pass-through mechanism is an efficient low cost method of managing unpredictable, high cost events that are beyond the control of AusNet Services. This mechanism ensures that costs are only recovered from customers if pre-defined events occur and are responded to efficiently.
- We are proposing seven nominated cost pass-through events to apply in the 2023-27 regulatory control period. These are:
  - Insurance Coverage event;
  - Terrorism event;
  - Natural Disaster event;
  - Insurer Credit Risk event;
  - Contamination Remediation event;
  - Major Cyber event; and
  - Victorian Energy Minister's power to direct augmentation event.
- We have in place efficient and prudent risk mitigation measures to manage risk during the regulatory control period, which we utilise instead of relying on the pass-through mechanism. Through effective risk management, we ensure the safety, reliability, and security of supply to our customers as far as practicable.

12.2 Chapter structure

This chapter presents AusNet Services' proposed cost pass-through arrangements for the forthcoming 2023-27 regulatory control period. Cost pass-through arrangements enable adjustments (increases or decreases) to be made to a TNSP's allowed revenue during a regulatory period if a predefined event occurs that leads to a material change in the TNSP's costs.

This chapter is structured as follows:

- Section 12.3 provides an overview of the cost pass-through framework under the NER;
- Section 12.4 presents our proposed nominated cost pass-through events; and
- Section 12.5 discusses an event that falls under the prescribed pass-through framework.

12.3 Overview of cost pass-through framework

The cost pass-through framework provides a means for TNSPs to recover the efficient costs of uncontrollable material events that either cannot be insured for, or where the establishment of self-insurance is not economically viable. It ensures consumers do not pay for uncertain but significant costs unless these events occur. The alternative is for customers to provide a self-insurance allowance, which means that customers will face an increased cost whether or not an event occurs.

Clause 6A.7.3(a1) of the Rules states that the following are each a pass-through event for a transmission determination:

(1) A regulatory change event;

(2) A service standard event;

(3) A tax change event;

(4) An insurance event; and

(5) Any other event specified in a transmission determination as a pass-through event for the determination.

In relation to subclause (5) above, NER 6A.7.3 gives TNSPs the ability to nominate specific pass-through events as part of their Revenue Proposals. The AER must take into account the "nominated pass-through event considerations" in Chapter 10 of the Rules when determining whether to accept AusNet Services' nominated pass-through events. The nominated pass-through event considerations are:

- Whether the event proposed is an event covered by a category of pass-through event specified in NER 6A.7.3(a1)(1)-(4);
- Whether the nature or type of event can be clearly identified at the time the determination is made for the service provider;
- Whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event;
- Whether the relevant service provider could reasonably insure against the event or whether the event can be self-insured; and
- Any other matter the AER considers relevant and which the AER has notified TNSPs is a nominated pass-through event consideration.

12.4 Proposed nominated events

Pursuant to NER 6A.6.9(a), we propose the following nominated cost pass-through events for the forthcoming regulatory control period:

- Insurance Coverage event;
- Terrorism event;
- Natural Disaster event;
- Insurer Credit Risk event;
- Contamination Remediation event;
- Major Cyber event; and
- Victorian Energy Minister's power to direct augmentation event.

Having regard to the nominated pass-through event considerations, the nominated events should be accepted by the AER for the following reasons:

- None of the proposed events is covered by one of the prescribed pass-through events in NER 6A.7.3(a1)(1)-(4);
- The nature and type of each event is clearly identifiable;
- Both the occurrence of each proposed event, and the mitigation of expenditure associated with those events are outside the control of a prudent network service provider;

- None of the proposed events are insurable on reasonable commercial terms; and
- It is not possible to calculate credible self-insurance premiums for the proposed events.

We consider that the nominated pass-through events we are proposing are consistent with the considerations and the intent of the NER. These pass-through events are nominated on the basis that it is not always efficient for TNSPs to fully insure against high impact, low probability events. Nevertheless, we remain committed to maintaining the necessary risk mitigation processes we already have in place, in conjunction with the pass-through framework.

The sections below present the event definition for each of our proposed nominated pass-through events, and a more detailed explanation of the rationale and need for each event.

12.4.1 Insurance Coverage Event

12.4.1.1 Proposed definition of event

The proposed definition of an Insurance Coverage event is as follows:

A. *An Insurance Coverage event occurs if AusNet Services:*

   a. *makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy or set of insurance policies; or*

   b. *would have been able to make a claim or claims under a relevant insurance policy or set of insurance policies but for changed circumstances,*

   and AusNet Services:

   c. *is required to pay a deductible in respect of a claim or claims; or*

   d. *incurs costs beyond a policy limit for the relevant insurance policy or set of insurance policies; or*

   e. *incurs costs that are unrecoverable under the relevant insurance policy or set of insurance policies (whether wholly or in part) due to changed circumstances,*

   and the costs referred to in paragraphs (c)-(e) above, either separately or in aggregate, increase the cost to AusNet Services of providing prescribed transmission services.

B. *For the purposes of this Insurance Coverage event:*

   a. 'changed circumstances' *means movements in the relevant insurance liability market since the acquisition of the insurance policy or set of insurance policies that applied during the majority of AusNet Services' base year and that are beyond the reasonable control of AusNet Services, where those movements result in it no longer being prudent or efficient for AusNet Services to take out with a reputable insurer:*

      i. *a relevant insurance policy; or*

      ii. *in the case of a set of insurance policies, one or more layers of insurance within that set (or there are otherwise one or more gaps within the set),*

   either at all or on commercial terms reasonable to AusNet Services.

   b. 'costs' *include:*

      i. *the deductible payable under a relevant insurance policy or set of insurance policies;*

      ii. *the amount or amounts that would have been recovered under the relevant insurance policy or set of insurance policies:*

         1. *had the limit not been exhausted; or*

         2. *but for the changed circumstances.*

c. 'reputable insurer*' means an insurer with a current financial security rating of A- or better by Standard and Poor's (or the equivalent rating with another reputable rating agency).*

d. *'*relevant insurance policy*' or '*set of insurance policies*' is an insurance policy or set of insurance policies held during the regulatory control period or a previous regulatory control period in which AusNet Services was regulated.*

e. *AusNet Services will be deemed to have made a claim on a relevant insurance policy or set of insurance policies if the claim is made by a related party of AusNet Services in relation to any aspect of AusNet Services' network or business.*

f. *AusNet Services will be deemed to have been able to make a claim on a relevant insurance policy or set of insurance policies if, but for changed circumstances, the claim could have been made by a related party of AusNet Services in relation to any aspect of AusNet Services' network or business.*

C. *For the avoidance of doubt, in assessing an Insurance Coverage event pass through application under clause 6A.7.3(j), the AER will have regard to:*

a. *the relevant insurance policy or set of insurance policies for the event;*

b. *the level of insurance that an efficient and prudent TNSP would obtain, or would have sought to obtain, in respect of the event;*

c. *any guidance published by the AER on matters the AER will likely have regard to in assessing an Insurance Coverage event; and*

d. *any information provided by AusNet Services to the AER about AusNet Services' actions and processes.*

12.4.1.2 Rationale

We consider that nominating an Insurance Coverage event as a cost pass-through event is a prudent and efficient way to mitigate the risk that we incur liability losses that exceed our insurance coverage. These losses can arise because commercial insurance cover for events may either be unavailable or may only be available at a prohibitively high cost, and it is inefficient to set aside an additional annual self-insurance allowance in a reserve given the size of the reserve required, the face it may need to be maintained for a significant period of time, and the fact that it may never be needed. These consequences all create unnecessary costs for consumers.

The AER has previously determined that an insured event that results in the NSP incurring costs beyond its insurance coverage would usually be triggered by circumstances beyond the NSP's control and would likely incur costs of a high magnitude that could not be forecast.[127] Absent the insurance coverage event pass-through, we would be precluded from receiving the opportunity to recover at least the efficient costs we incur in providing prescribed transmission services because the costs of an insurance coverage event have not been allowed for elsewhere in this proposal.

Our proposed definition of an Insurance Coverage event is largely consistent with the AER's most recent determination for SA Power Networks[128] but proposes further refinements that align with AER policy objectives.

[127] AER, *Draft decision – AusNet Services distribution determination 2021-26 - Attachment 15 – Pass through events - September 2020*, p. 12.

[128] AER, *Final decision - SA Power Networks distribution determination 2020-25 - Attachment 14 - Pass through events - June 2020*, p. 5.

12.4.1.3 Risk mitigation

We acknowledge the complementary nature of commercial insurance coverage and the pass-through framework, which gives AusNet Services the opportunity to achieve an optimal blend of cover. As an efficient and prudent NSP, we set our insurance limits based on a level of insurance cover that is commensurate with the scale and size of our operations, the risks assessed to be associated with our operations, as well as industry standards and practices.

12.4.2 Terrorism Event

12.4.2.1 Proposed definition of event

The proposed definition of a Terrorism event is as follows:

1. *A Terrorism event means an act (including, but not limited to, the use of force or violence or the threat of force or violence) by any person or any group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which:*
   (a) *from its nature or context is done or appears to be done for or in connection with political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear); and*

   (b) *increases the cost to AusNet Services in providing prescribed transmission services.*
2. *In assessing a Terrorism event pass through application, the AER will have regard to, amongst other things:*
   (a) *whether AusNet Services has insurance against the event;*

   (b) *the level of insurance that an efficient and prudent TNSP would obtain in respect of the event; and*

   (c) *whether a declaration has been made by a relevant government authority that an act of terrorism has occurred.*

12.4.2.2 Rationale

An act of terrorism against national critical infrastructure such as an electricity transmission network can reasonably be expected to have a significant impact on the cost of providing services over the network. For example, immediate physical repairs to infrastructure may be required to maintain or restore reliable supply. It may also be necessary to implement additional security processes and introduce new preventative measures to deter or prevent future attacks. Depending on the scale and impact of the event, the cost impact on the provision of prescribed transmission services may be significant.

We agree with the AER that AusNet Services is best placed to manage the majority of the risk posed by an act of terrorism. To that end, we have taken a number of steps to substantially mitigate risks posed by an act of terrorism to our network, which are detailed in section 12.4.2.3 below. However, it is not possible to eliminate the entirety of the risk we face as to do so would require a level of expenditure (and therefore a cost to our customers) that is neither prudent nor efficient.

Therefore, we consider it appropriate to share part of the risk of an act of terrorism occurring with our customers by including a nominated pass-through event for the 2023-27 regulatory control period.

Our current transmission determination includes a Terrorism event as a nominated cost pass-through event. We have reviewed the AER's analysis of the terrorism event definitions proposed by other network service providers recently[129] and do not consider there is a strong need to change our current definition. We do note, however, that the scope of paragraph (a) may unnecessarily limit our ability to access the event. Currently, paragraph (a) requires that the nature or context of the act of terrorism show a political, religious, ideological, ethnic, or similar motivation for the conduct. In some cases, it may not be possible to conclude (or even to infer) the motivation of the acting party or parties. Therefore, we have inserted the phrase "or appears to be done" after the words "from its nature or context is done" to remove this uncertainty. If the AER accepts the merit in this change, an equivalent amendment could be incorporated into AusNet Services' distribution terrorism event definition (and those of the other Victorian DNSPs') to promote consistency within the jurisdiction.

12.4.2.3 Risk mitigation

As noted above, AusNet Services has several security and other measures in place to prevent acts of terrorism, and to mitigate the cost impact of such an event, should one occur. We manage these risks by focusing primarily on the protection of key assets and critical infrastructure, including the software and underlying technology used to operate those assets. For example, our foundational security capabilities include:

- ensuring appropriate physical security controls are in place to deter, detect or respond to physical security breaches, including installing CCTV cameras at all major asset sites and employing security patrols; and
- taking reasonable steps to design, operate and maintain our IT systems in accordance with *ISO 27001: Information Security Management and ISO 27002 Information Technology: Security Techniques – Code of Practice for information security controls*, which represents international best practice for IT security.

We periodically test whether it is cost-effective to obtain third party insurance or to self-insure against losses resulting from acts of terrorism. The relative infrequency and potentially very high costs of a terrorism event creates significant practical challenges for insuring such events, including calculating the amount of cover required and the self-insurance premium required. Having regard to with the nominated pass-through event considerations specified in NER Chapter 10, a pass-through mechanism provides a more efficient arrangement for managing the cost impacts in the unlikely circumstances that a terrorism event occurs and materially increases our costs.

12.4.3 Natural Disaster Event

12.4.3.1 Proposed definition of event

The proposed definition of a Natural Disaster event is as follows:

1. *Natural Disaster Event means a natural disaster including but not limited to fire, flood or earthquake that occurs during the 2023-27 regulatory control period and that increases the costs to AusNet Services of providing prescribed transmission services, provided the fire, flood or other event is:*

   (a) not a consequence of the acts or omissions of AusNet Services; or

   (b) a consequence of an act or omission that was necessary for AusNet Services to comply with a regulatory obligation or requirement or an applicable regulatory instrument.

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[129] AER, *Draft decision, SA Power Networks Distribution Determination 2020 to 2025, Attachment 14 Pass through events*, October 2019, 11-12; AER, *Draft decision, Powercor Distribution Determination 2021 to 2026, Attachment 15 Pass through events*, September 2020, 15.

2. *In assessing a Natural Disaster event pass through application, the AER will have regard to, amongst other things:*
   (a) *the extent to which AusNet Services holds insurance against the event; and*
   (b) *the level of insurance that a prudent and efficient TNSP would obtain in respect of the event.*

12.4.3.2 Rationale

Natural disaster events, by definition, cannot be prevented or avoided. The cost impact of a natural disaster on our network assets can be potentially significant. Potential natural disasters that could cause significant property damage include, but are not limited to, bushfires, earthquakes, storms, floods and other naturally occurring weather phenomena. Where it is possible, our insurance coverage provides some protection against loss and damage caused by natural disasters; however, the cost impact of a natural disaster could materially exceed the coverage provided by these policies. Furthermore, there are events, such as the tower collapse, that are not covered by insurance. Finally, the probability of natural disasters occurring is sufficiently low that it is not prudent or efficient to obtain continuous insurance cover and pass this cost onto consumers.

Our proposed definition of a Natural Disaster event is consistent with the AER's most recent determination for SA Power Networks.[130]

12.4.3.3 Risk mitigation

We employ a range of strategies to minimise and mitigate the exposure of the transmission network to natural disasters. For the majority of our assets, exposure to natural disasters is reduced as far as reasonably practicable through minimum design standards to ensure assets can withstand seismic, flood and fire (and other natural catastrophes). The integrated nature of the network can also allow for supply to continue uninterrupted when assets are affected by natural disaster events. We also invest in restoration and recovery capability including key spares and temporary towers, such as the kind deployed following the recent transmission tower collapse near Cressy. Where it is feasible and efficient to do so, we also seek to transfer the risks posed by natural disasters by obtaining external insurance cover or self-insuring. However, as the AER is aware, complete insurance cover for natural disaster events (particularly fires) is either not available, or not available at an efficient cost.

These considerations demonstrate the need for the Natural Disaster event, which provides the most cost-effective risk mitigation strategy.

12.4.4 Insurer Credit Risk Event

12.4.4.1 Proposed definition of event

The proposed definition of an Insurer's Credit Risk event is as follows:

1. *An Insurer's Credit Risk event occurs if a nominated insurer of AusNet Services becomes insolvent, and, as a result, in respect of an existing, or potential, claim for a risk that was insured by the insolvent insurer, AusNet Services:*
   (a) *is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the insolvent insurer's policy; or*

[130] AER, *Final decision - SA Power Networks distribution determination 2020-25 - Attachment 14 - Pass through events - June 2020*, p. 6.

(b) *incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer.*

2. *In assessing an Insurer's Credit Risk event pass through application, the AER will have regard to, amongst other things:*

   (a) *AusNet Services' attempts to mitigate and prevent the event from occurring by reviewing and considering the insurer's track record, size, credit rating and reputation; and*

   (b) *in the event that a claim would have been made after the insurance provider became insolvent, whether AusNet Services had reasonable opportunity to insure the risk with a different provider.*

12.4.4.2 Rationale

The cost impacts to us of one of our insurers becoming insolvent are potentially significant. By being forced to insure with another provider, we could be forced to accept higher premiums, or a lower claim limit or higher deductible. Our insurance coverage is significant and hence an insurer being unable to pay a claim, or part of a claim, could materially affect our ability to provide prescribed transmission services to our customers.

Although we mitigate this risk to the best of our ability by ensuring our insurers have the equivalent of an S&P rating of A or above, the insolvency of one or more of our insurers is an event that is outside our control. The probability of insurer insolvency is also such that it is not prudent or efficient to remove the risk altogether. Hence, we believe that a pass-through mechanism is currently the most appropriate regulatory approach for addressing the costs arising from an insurer becoming insolvent.

Our proposed definition aligns with that approved by the AER in its final decision for SA Power Networks.[131]

12.4.4.3 Risk mitigation

We set minimum requirements and consider several risk management factors when assessing whether to insure with a particular provider, such as the insurer's track record, size, credit rating and reputation. Our insurance coverage is also diversified across both domestic and international providers. The combination of these approaches can be considered to provide a prudent and efficient level of risk mitigation against a potential insurer credit risk event.

12.4.5 Contamination Remediation Event

12.4.5.1 Rationale

Amendments made by the *Environment Protection Amendment Act 2018* (Vic) to the *Environment Protection Act 2017* (Vic) will impose new obligations on AusNet Services from 1 July 2021. These include, most notably, the introduction of a general environmental duty, a duty to manage contaminated land and a duty to notify of contaminated land. To meet these new obligations, we have forecast an opex step change of $3.1 million to establish a new testing regime.

The Environmental Protection Authority (**EPA**) is also expected to create new instruments under the amended legislation prior to the start of the 2023-27 regulatory control period. To the extent that these instruments prescribe the manner in which AusNet Services is required to discharge its new obligations, we consider they are likely to constitute a regulatory change event in that they

[131] AER, *Final decision - SA Power Networks distribution determination 2020-25 - Attachment 14 - Pass through events - June 2020*, p. 6.

satisfy paragraph (1)(b)(iii) or (iv) of the definition of a regulatory obligation or requirement,[132] which respectively refer to obligations or requirements under legislation or instruments that regulates the use of land or relates to the protection of the environment.

As noted above, following the commencement of the amendments, AusNet Services will be required to test for historical contamination and notify the EPA of any contaminated land sites.[133] The cost of complying with this obligation, which includes conducting rigorous testing and risk assessments, is included in AusNet Services' opex forecast. However, no provision has been made for the cost of managing a site found to be contaminated. It is possible that these costs could be significant.

AusNet Services does not consider the obligation to manage contaminated land can be treated as a regulatory change event because the trigger event for the pass-through application is not the making or amendment of a regulatory obligation or requirement, but rather the discovery of contaminated land. This combined with the uncertainty about whether contaminated land will be discovered and the cost of managing that land (which may include remediation), AusNet Services considers this risk is most appropriately addressed by a nominated pass-through event. The proposed Contamination Remediation event meets all of the requirements of the nominated pass-through event considerations.

12.4.5.2 Proposed definition of event

The proposed definition of a Contamination Remediation event is as follows:

1. A Contamination Remediation event occurs if:

> *(a) AusNet Services is required to perform a program of remediation or similar works in order to comply with an obligation imposed by:*
>
> > *(i) an amendment made to the* Environmental Protection Act 2017 *(Vic) by the* Environment Protection Amendment Act 2018 *(Vic); or*
> >
> > *(ii) any instrument made or issued under or for the purposes of the* 2017 Act *(as amended); and*
>
> *(b) the cost of performing the program of works in order to comply with the obligation or obligations referred to in paragraph (a) were not included in the capital or operating expenditure forecasts proposed by AusNet Services and approved by the AER for the 2023-27 regulatory control period; and*
>
> *(c) the cost of complying with the obligation or obligations referred to in paragraph (a) increases the cost to AusNet Services of providing prescribed transmission services.*

12.4.5.3 Risk mitigation

We have developed sophisticated Health Safety, Environment and Quality (HSEQ) programs for the assessment of potential contamination and associated risks to both human health and the environment for each permanent site.

12.4.6 Major Cyber Event

12.4.6.1 Rationale

The risk, frequency and severity of cyber-attacks is increasing rapidly. The Federal Government has recognised that there have been several cyber-attacks in Australia in recent years that have

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[132] Section 2D(1)(b)(iii) of the National Electricity Law. A change in a regulatory obligation or requirement that meets the requirements set out in the definition of regulatory change event in Chapter 10 is a pass through event under clause 6A.7.3(a1).

[133] A site will be assessed as contaminated where there is a clear risk of harm to human health and the environment.

targeted the Federal Parliamentary network, airports, universities, health organisations, medical research facilities and other key supply chain businesses.[134] The Victorian Government's *Critical Infrastructure Resilience Strategy* acknowledges that cyber-attack is a global risk that is evolving rapidly as new technologies and systems emerge.[135] In light of the significant economic, social, environmental, political and national security costs that a cyber-attack can have, the Government considers cyber-attack is one of the emergency risks for which Victorian critical infrastructure owners and/or operators must prepare.[136]

We consider the probability of an attack to be low (although, as noted above, this probability is steadily increasing) but the consequences to be potentially severe. We play a critical role in the energy sector, linking generators to the Victorian-based DNSPs that supply electricity to end use customers, as well as our role in the wider NEM, where cross-border interconnectors link the Victorian transmission network to SA and NSW, allowing electricity to flow from one state to another. As a result, we are a key source of energy and any major cyber event that affects our assets would have significant and wide-ranging repercussions for electricity supply across the NEM.

AusNet Services acknowledges the AER's view that a major cyber-attack is a standard business risk that an NSP should manage.[137] AusNet Services has implemented a number of measures to avoid such an attack, and to respond quickly in the event that one does in occur in order to mitigate its impact, both operationally and financially. Given the importance of our role in the NEM, the cyber security protections we employ are required to be more stringent in comparison to Victoria's DNSPs. We outline our measures in 12.4.6.3 below.

Despite the preventative and remedial measures we have in place, there remains a material risk that if a cyber-attack occurs, AusNet Services will not be able to recover the totality of the costs associated with the attack. These costs might include the costs incurred to restore the network to full operational capability, expenditure necessary to recreate or restore data and information, and the purchase and installation of additional cyber security tools and software to prevent further attacks. Therefore, we consider it is appropriate to propose a Major Cyber Event for inclusion as a nominated pass-through event in our transmission determination for the 2023-2027 regulatory control period.

We note that the AER has considered proposals to include a 'major cyber event' as a nominated pass-through event in a number of recent regulatory decisions.[138] One of the reasons it has not accepted the event is that a cyber-attack can amount to terrorism and therefore fall within an NSP's Terrorism Event definition.[139]

AusNet Services does not agree that the Terrorism Event definition makes adequate provision for a major cyber event of the kind we propose. While there may be cyber events that constitute

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[134] Department of Home Affairs, *Protecting Critical Infrastructure and Systems of National Significance, Consultation Paper*, August 2020, pg. 6.

[135] Victorian Government, *Critical Infrastructure Resilience Strategy*, Melbourne, July 2015, 11, <https://files-em.em.vic.gov.au/public/EMV-web/Critical-Infrastructure_Resilience_Strategy_Sept-2016.pdf>.

[136] Ibid.

[137] AER, *Draft Decision, Essential Energy distribution, 2019-24, Attachment 14*, November 2018, 13; AER, *SA Power Networks Distribution Determination 2020 to 2025, Draft Decision, Attachment 14 Pass through events*, October 2019, 13.

[138] AER, *Draft Decision, Essential Energy distribution, 2019-24, Attachment 14,* November 2018; AER, *SA Power Networks Distribution Determination 2020 to 2025, Draft Decision, Attachment 14 Pass through events*, October 2019; AER, *Draft decision, Powercor Distribution Determination 2021 to 2026, Attachment 15 Pass through events*, September 2020; AER, *Draft decision, CitiPower Distribution Determination 2021 to 2026, Attachment 15 Pass through events*, September 2020; AER, *Draft decision, United Energy Distribution Determination 2021 to 2026, Attachment 15 Pass through events*, September 2020.

[139] AER, *Draft decision, Powercor Distribution Determination 2021 to 2026, Attachment 15 Pass through events*, September 2020, 17.

cyber terrorism and fall within the Terrorism Event definition, this will not always be the case. It could be because the motivation for the cyber event either cannot be determined or does not meet the requirements specified in paragraph 1(a) of the Terrorism Event definition. This leaves a gap in the cost pass-through framework because it prevents an NSP from being able to pass-through the costs of the event because of an inability to determine the motivation of the perpetrator(s) of a major cyber-attack. We do not consider it appropriate that an NSP should be disadvantaged in this way.

To the extent that a major cyber-attack does meet the definition of a Terrorism Event, our proposed event definition ensures the event is covered by only one category of pass-through event.

The AER has also previously commented that they will only accept nominated pass-through events where they are satisfied that event avoidance, mitigation, commercial insurance and self-insurance under approved forecasts of prudent and efficient opex and capex are either unavailable or inappropriate.[140] The longstanding nominated events which have been accepted in previous determinations (such as Natural Disaster and Terrorism) are predominantly designed to protect the physical security of NSP assets from the ever-present physical risks in society. We agree that avoidance, mitigation, and the procurement of insurance for these types of events are unavailable or inappropriate under a prudent and efficient expenditure forecast. However, the transition to a more digital way of working (accelerated further by the COVID-19 pandemic) has led to a shift in the likelihood of risks from physical security to cyber security. Therefore, this lends support to the Major Cyber event, as there is no equivalent protection for cyber related assets in the pass-through framework as there is for physical assets.

12.4.6.2 Proposed definition of event

The proposed definition of a Major Cyber event is as follows:

1. *A Major Cyber event is any significant and deliberate interference with AusNet Services' technology systems or assets (including, but not limited to, the introduction of malicious or harmful software, code or viruses to computer systems or networks, or to data or communication systems) carried out, directed or otherwise caused by an act of a third party that:*
   - *(a) falls into no other category of pass through event; and*
   - *(b) increases the costs to AusNet Services of providing prescribed transmission services.*
2. *In assessing a Major Cyber Event pass through application, the AER will have regard to, amongst other things:*
   - *(a) the steps AusNet Services took to prevent the event from occurring and to mitigate its consequences; and*
   - *(b) the level and scope of any insurance AusNet Services holds in respect of a Major Cyber Event.*

12.4.6.3 Risk mitigation

In recent regulatory decisions, the AER has disallowed the inclusion of a 'major cyber event' as a nominated pass-through event primarily because it was not satisfied that the proponent could not reasonably prevent or substantially mitigate the cost impact of such an event, or insure or self-

[140] AER, *SA Power Networks Distribution Determination 2020 to 2025, Draft Decision, Attachment 14 Pass through events*, October 2019, 10.

insure against such an event. AusNet Services views cyber-attacks as a key business risk and uses a number of strategies in an effort to manage them appropriately.[141]

Consistent with the AER's expectation,[142] AusNet Services currently holds a cyber security insurance policy with an aggregate limit of $20 million.

[C-I-C]

However, while our insurance policies do provide some cover against losses caused by a major cyber event, the cost impact of such an event could exceed the limits or scope of these policies.

Furthermore, although we have been able to secure cover this year, AusNet Services understands that some property and liability insurers are contemplating applying a cyber exclusion on their policies. If this were to happen, it may be problematic for AusNet Services to obtain the level of cyber coverage in the future that would be expected of a prudent TNSP. Accordingly, insurance cover cannot be assumed to be available at current levels for the duration of the forthcoming regulatory control period.[143]

By virtue of our role as the owner and operator of national critical infrastructure, AusNet Services is also subject to stringent cyber security compliance requirements. Consequently, some of the safeguards and contingency plans we have in place to deter cyber-attacks and mitigate their impact should one occur include avoiding or reducing:

- Loss of supply to customers arising as a result of a cyber-attack shutting off energy supply;
- Risk of system failure requiring remediation, including activities to restore systems, data and supporting processes impacted by a cyber security attack;
- Risk of system failure to public assets. This includes activities to restore or repair public assets suffering damage due to a cyber security attack. This could arise for example from a surge in electricity on the LV line damaging customer meters or appliances; and
- Reductions to staff productivity from being unable to access systems required to carry out duties as a result of system failure.

We have proposed opex and capex in the amount of $27.9 million opex (via a step change) and $16.9 million capex to improve our capability to proactively identify, protect, deter, respond to, and recover from cyber security threats. In particular, the AER's consultant, EMCa noted that achieving MIL 2 is prudent for AusNet Distribution, while achieving MIL 3 is prudent for AusNet Transmission as follows:

> "Our understanding is that TNSPs are in the 'Highly Critical' group. As AusNet states, there is not currently a regulatory obligation for it to achieve MIL 3 by a specific deadline. However, based on information regarding assessed criticality and escalating cyber threat levels, we acknowledge that AusNet's intention for its Transmission business to enhance

[141] AER, *Draft Decision, Essential Energy distribution, 2019-24, Attachment 14*, November 2018, 13; AER, *SA Power Networks Distribution Determination 2020 to 2025, Draft Decision, Attachment 14 Pass through events*, October 2019, 13.

[142] Ibid.

[143] AusNet Services acknowledges that, were there to be shortfall in available insurance cover below the level that a prudent and efficient TNSP would obtain, there may be a basis for submitting a claim for an Insurance Coverage Event. The drafting of the Major Cyber Event definition ensures the proposed event complies with paragraph (a) of the nominated pass through event considerations.

its cyber security level towards MIL 3 in the next RCP is likely to represent the actions of a prudent TNSP operator."[144]

The other risk mitigation strategies we employ include maintaining detailed Incident Response Plans as part of our wider cyber incident readiness assessment, which we are ready to implement should a major cyber incident occur. We consider this an appropriate and robust framework of risk mitigation to safeguard our systems and assets against the risks and cost impacts of cyber-attacks.

We also undertake prudent and efficient capital and operating expenditure during each regulatory control period to ensure we proactively identify, protect, deter, respond to, and recover from cyber security threats. Some of the steps we have taken for this purpose include:

[C-I-C]

The AER has disallowed previous 'major cyber event' definitions because it was not satisfied that the NSP could not reasonably prevent or substantially mitigate the cost impact of such an event, or insure or self-insure against such an event.[145] In our view, the actions and strategies outlined in this section demonstrate that we have taken the prudent and efficient steps available to us to deter or mitigate the effects of a major cyber-attack. As such, we believe the nominated pass-through event considerations are satisfied and it is appropriate that the AER accept our Major Cyber Event as proposed.

12.4.7 Victorian Energy Minister's power to direct augmentation Event

12.4.7.1 Rationale

There may be circumstances in which it is necessary for AusNet Services to apply to pass-through costs arising from the Victorian Energy Minister's new power to direct transmission network augmentation.

On 25 March 2020, amendments to the *National Electricity (Victoria) Act 2005* (Vic) (NEVA) commenced, which empower the Victorian Minister for Energy to make a Ministerial order to regulate:[146]

- Specified augmentations of the declared transmission system;
- The provision of specified non-network services in respect of such augmentations; and

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[144] EMCa, *AusNet Services - Review of proposed opex ICT-related step changes: Report prepared for: Australian Energy Regulator* (August 2020).

[145] AER, *Draft Decision, Essential Energy distribution, 2019-24, Attachment 14*, November 2018, 13; AER, *SA Power Networks Distribution Determination 2020 to 2025, Draft Decision, Attachment 14 Pass through events*, October 2019, 14-15.

[146] *National Electricity (Victoria) Amendment Act 2020*, section 4.

- Other services that support the Victorian transmission system.

The Minister's new powers are intended to expedite specified transmission system augmentations to improve the reliability of electricity supply by allowing the Minister to, amongst other things, modify the requirements of the Regulatory Investment Test for transmission (RIT-T) and provide for the recovery by AEMO and other parties of costs incurred in respect of a specified augmentation or the provision of specified non-network services. At this time, it is not possible for AusNet Services to predict with any certainty how the Minister might exercise this power or what a Ministerial Order made might contain. It is reasonable to expect an Order to create new obligations or vary existing obligations on AusNet Services. For example, an Order may require a battery to be installed, new transmission lines to be constructed, or existing lines upgraded. To the extent that compliance with an Order increases the cost to AusNet Services of providing prescribed transmission services, the Revenue and Pricing Principles[147] require that we be provided a reasonable opportunity to recover at least our efficient costs.

To this end, the regulatory framework contains mechanisms to enable efficient costs to be recovered. However, these mechanisms are not, or are unlikely to be, available to AusNet Services in all circumstances in respect of costs arising from a Ministerial Order. For instance, as no Order has yet been made, AusNet Services cannot develop expenditure forecasts for inclusion in this regulatory proposal. Similarly, the cost pass-through mechanism provided for in clause 6A.7.3 of the NER is unlikely to be an effective pathway for cost recovery because a Ministerial Order will not constitute a regulatory change event under clause 6A.7.3(a1)(1). This is because an Order cannot be a "regulatory obligation or requirement"[148] because it is an instrument made under national electricity legislation and, therefore, is excluded from being an obligation or requirement under section 2D of the NEL.[149] Further, we do not consider that a Ministerial Order would satisfy the requirements of any of the other pass-through events specified in clause 6A.7.3(a1).

Based on the current allocation of transmission network responsibilities in Victoria, it is the case that AEMO, as the party ordinarily responsible for planning augmentations on the declared shared network, and AusNet Services, as a DTSO and the provider of connection services, enters into contractual arrangements in order to deliver specified augmentations. Therefore, consistent with the existing contractual framework, we expect AusNet Services' costs associated with delivering augmentations required by a Ministerial Order to be recovered pursuant to those arrangements.

However, contractual recovery will not be available in all cases. Specifically, if the Ministerial Order were to direct AusNet Services to augment the network (i.e. bypassing AEMO), there is unlikely to be a contractual framework to enable cost recovery. The NEVA contemplates this possibility and similar situations where recovery pursuant to this contractual framework is not possible or preferred. Section 16Y(2)(g) empowers the Order to itself provide for AusNet Services to access the cost pass through mechanism in the NER by expressly permitting it to "provide that augmentation related costs or non-network services costs may be recovered as a pass-through event subject to, and in accordance with, Chapter 6A of the Rules".

If the Ministerial Order does not make provision for us to access the cost pass through mechanism and because the making of an Order does not meet the definition of any of the prescribed cost pass through events for the reasons outlined above, AusNet Services considers that a nominated cost pass through event is required to give effect to the cost recovery arrangements contemplated in the NEVA.

[147] Section 7A (2), National Electricity Law.

[148] This term is defined in section 2 of the National Electricity Law.

[149] Section 2D(1)(b), National Electricity Law

We would welcome the opportunity to meet with the Victorian Government and the AER during the remainder of the regulatory review process to continue discussions regarding the proposed cost pass through event to ensure it reflects the most appropriate cost recovery mechanism available in the circumstances described above.

12.4.7.2 Proposed definition of event

The proposed definition of the Ministerial Transmission Augmentation Order Event is as follows:

1. *A Ministerial Transmission Augmentation Order event occurs if each of the following conditions are satisfied:*

   (a) *the Minister makes an order under section 16Y(1) of the* National Electricity (Victoria) Act 2005 *(Vic) (Order);*

   (b) *complying with the Order, or assisting AEMO or a third party to comply with its obligations under the Order, increases the cost to AusNet Services of providing prescribed transmission services.*

12.4.7.3 Risk mitigation

AusNet Services expects that a Ministerial Order will provide for access to the NER cost pass-through mechanism or by providing such other opportunity to enable AusNet Services a reasonable opportunity to recover our efficient costs. However, given the novelty of the Ministerial power, the lack of certainty about how the power might be exercised, the scope of the prescribed cost pass-through events and the extremely limited grounds for re-opening a transmission determination, AusNet Services is proposing a nominated cost pass-through event (the Ministerial Transmission Augmentation Order Event) for inclusion in the 2023-2027 regulatory determination.

12.5 Events that fall under the prescribed pass-through framework

12.5.1 Network support costs

Rapid changes to the generation mix, from traditional to renewable sources, is compromising the system security of Victoria's transmission network. This is also reducing the window of opportunity to undertake planned outage activities and maintain our assets. These windows may reduce to such an extent that AusNet Services cannot adequately maintain its assets unless AEMO, in its capacity as the Victorian transmission planning authority, augments the network.

AEMO has advised AusNet Services that if we take outages outside of the windows approved by AEMO (in its capacity as the system operator), even if doing so would be advantageous from a market impact perspective,[150] then we should procure network support in order to ensure AEMO can maintain system security for the duration of the outage. We are currently conducting a full costing exercise with a network support provider to ascertain the full cost of the associated network support that are likely to be required in the upcoming regulatory control period.

As the expected network support costs remain uncertain at the time this proposal is submitted, we do not consider it prudent to make provision for this expenditure in our opex forecast at this time. Rather, we consider the network support pass-through mechanism under clause 6A.7.2 of the NER is the most appropriate mechanism for recovering these costs.

[150] AEMO provides limited windows of opportunity for AusNet Services to take planned outages due to the system security strength issues posed with taking such outages.

12.6 Supporting documentation

The following documentation is provided in support of this chapter:

- Appendix 12A – Insurance Certificate of Currency.

13 Maximum allowed revenue and price path

13.1 Key points

The key points in this chapter are:

- Our proposed revenue requirement for the 2023-27 regulatory control period is $2,647 million in unsmoothed real 2021-22 dollars.
- On average, our proposed revenue requirement is $529 million. This is 8% less than expected revenue during the current regulatory period.
- Excluding easement land tax and council rates increases, which are uncontrollable, our proposed average annual revenue requirement is $352 million. This is 15% less than expected revenue in the current period.
- We estimate that after these uncontrollable costs, AEMO's costs and customer growth are taken into account, the average transmission charge per customer will fall by 8% in real terms.

13.2 Chapter structure

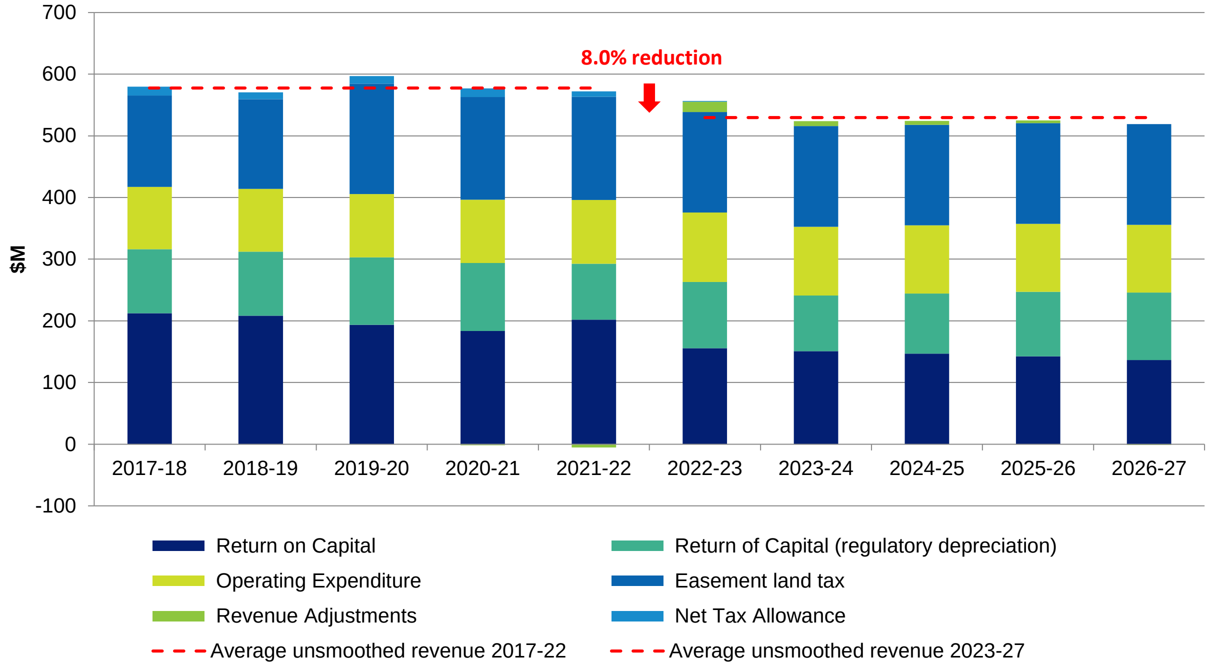
This chapter is structured as follows:

- Section 13.3 provides a summary of our revenue requirement;
- Section 13.4 explains the building blocks of our revenue requirement (unsmoothed);
- Section 13.5 provides a summary of our smoothed revenue requirement;
- Section 13.6 sets out our average transmission charges; and
- Section 13.7 provides a summary of our supporting documentation.

13.3 Summary of our revenue requirement

Based on the detailed inputs described and calculated in this Revenue Proposal, our average annual revenue requirement for the 2023-27 regulatory control period is $529 million (both smoothed and unsmoothed). As shown in Figure 13-1, our proposed unsmoothed revenue requirement is 8% lower than expected revenue in the current period.

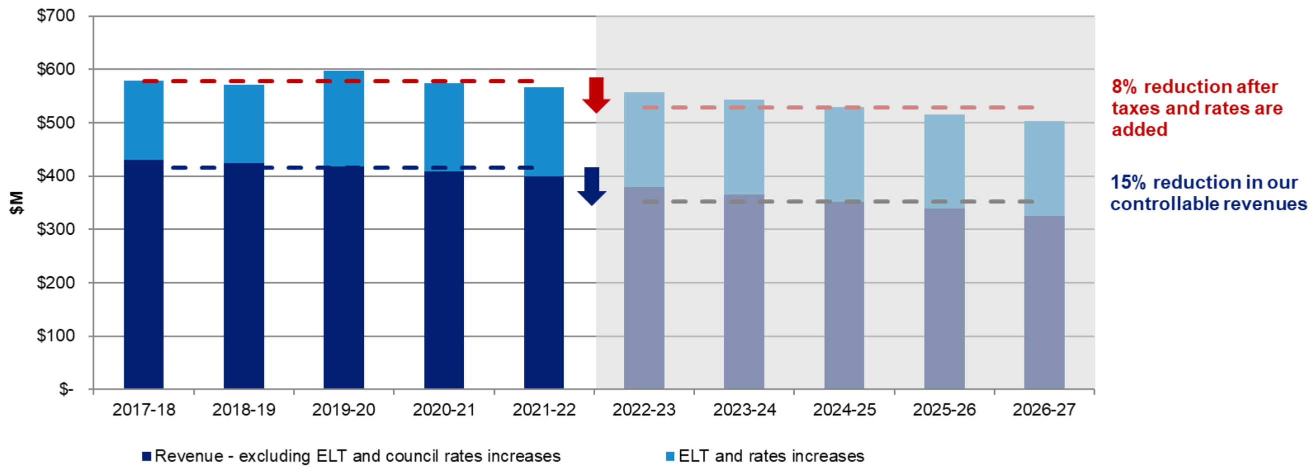
Figure 13-1: Actual, expected and forecast revenue requirement ($M, real 2021-22)



Source: AusNet Services

Excluding the easement land tax and anticipated increases in our council rates costs, which are uncontrollable, forecast revenue is $352 million per year, on average. This is 15% lower than controllable revenue in the current period.

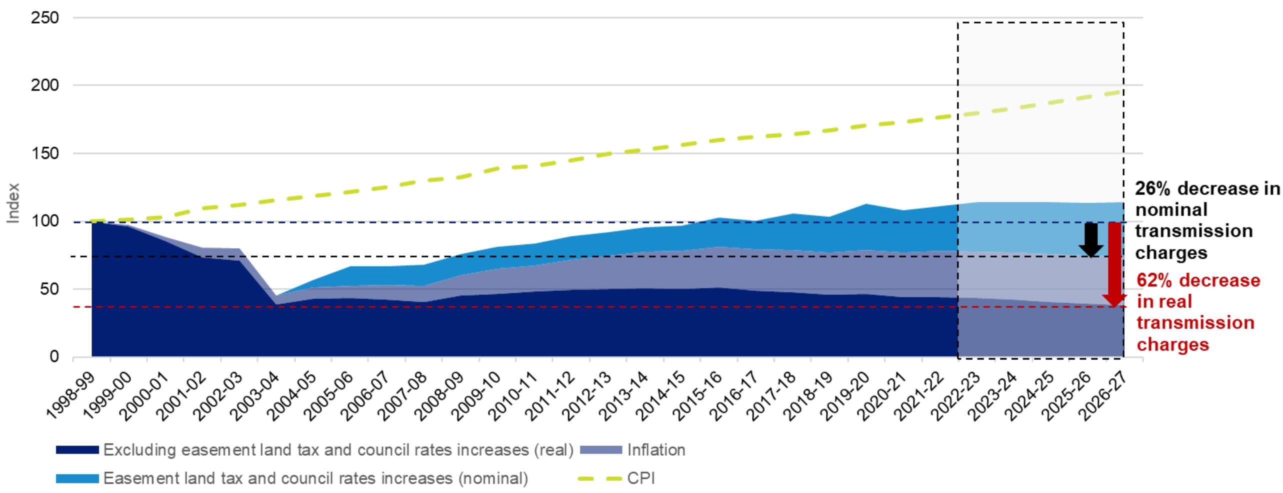
Figure 13-2: Actual, expected and forecast revenue ($M, real 2021-22)



Source: AusNet Services

Our revenue proposal will allow real transmission charges to be 62% lower than at privatisation more than 20 years ago (excluding easement land tax and increases in council rates) and, notwithstanding the effects of more than two decades of inflation, 26% lower in nominal terms. This reduction is despite forecast increases in operating and capital expenditure in the forthcoming regulatory control period which are necessary to replace ageing assets, manage new assets and meet new regulatory obligations.

Figure 13-3: Price growth since privatisation (index)



Source: AusNet Services

13.4 Building blocks of the revenue requirement (unsmoothed)

The building blocks of our unsmoothed revenue requirement for each year of the 2023-27 regulatory control period are summarised in Table 13-1.

Our unsmoothed annual revenue requirement is the sum of the building blocks. Earlier chapters explain the way each building block has been calculated, whereas the following sections provide a summary.

Table 13-1: Unsmoothed revenue requirements ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Return on capital	155.7	150.8	146.8	142.4	136.3	**731.9**
Regulatory depreciation	107.2	90.1	97.5	104.9	109.5	**509.3**
Operating expenditure excluding ELT	112.7	111.6	110.4	110.2	110.0	**554.7**
Easement land tax	163.2	163.2	163.2	163.2	163.2	**815.9**
Revenue adjustments	16.7	8.0	6.3	4.5	-1.3	**34.2**
Net tax allowance	1.1	-	-	-	-	**1.1**
Total	**556.5**	**523.6**	**524.2**	**525.1**	**517.7**	**2,647.1**

Source: AusNet Services

13.4.1 Return on capital

Consistent with the requirements of clause 6A.5.4(a)(2) of the NER, and in accordance with the AER's PTRM, the return on capital is calculated by applying the post-tax nominal vanilla WACC to the opening RAB for each year of the regulatory period. Table 13-2 summarises the calculation of the return on capital component of the building block approach.

Full details of the WACC calculation are set out in Chapter 10 of this Revenue Proposal.

Table 13-2: Return on capital ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Opening RAB	3,581.9	3,655.3	3,751.9	3,840.8	3,885.6	
WACC (% per annum)	4.44%	4.31%	4.18%	4.05%	3.92%	
Return on capital	**159.2**	**157.7**	**156.9**	**155.6**	**152.3**	**781.7**

Source: AusNet Services

Our return on capital in Table 13-2 is based on a RAB that we have calculated in accordance with the requirements of clause 6A.6.1 and schedule 6A.2 of the NER. It reflects our capital expenditure (capex) forecast set out in Chapter 4 of this Revenue Proposal, our opening RAB (Chapter 8) and our depreciation (Chapter 9). Table 13-3 summarises our RAB for the 2023-27 regulatory control period.

Table 13-3: Regulatory asset base ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27
Opening RAB	3,581.9	3,655.3	3,751.9	3,840.8	3,885.6
Net capital expenditure	183.0	190.8	193.2	159.4	129.0
Straight-line depreciation	-190.2	-176.4	-188.6	-201.0	-209.8
Indexation on opening RAB	80.5	82.2	84.4	86.4	87.4
Closing RAB	**3,655.3**	**3,751.9**	**3,840.8**	**3,885.6**	**3,892.2**

Source: AusNet Services

13.4.2 Regulatory depreciation

We have calculated regulatory depreciation in accordance with the requirements of clauses 6A.6.3, 6A.5.4.(a)(1) and (3) of the NER, and the AER's PTRM. Table 13-4 summarises our proposed regulatory depreciation.

Table 13-4: Regulatory depreciation ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Straight-line depreciation	190.2	176.4	188.6	201.0	209.8	**966.0**
Indexation on opening RAB	-80.5	-82.2	-84.4	-86.4	-87.4	**-420.9**
Total	**109.6**	**94.2**	**104.3**	**114.6**	**122.4**	**545.1**

Source: AusNet Services

13.4.3 Operating expenditure

Consistent with the requirements of clause 6A.5.4(a)(6) of the NER, we have included a forecast of operating expenditure (opex) in our building blocks revenue requirement. As explained in Chapter 5 of this Revenue Proposal, our opex forecast has been prepared in accordance with all applicable requirements of the NER and the RIN. Table 13-5 provides a summary of our forecast opex.

Table 13-5: Operating expenditure ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Controllable opex (base, step and trend)	113.4	114.8	116.1	118.5	121.0	**583.9**
Easement land tax	166.9	170.6	174.4	178.4	182.4	**872.6**
Debt raising cost	1.8	1.8	1.9	1.9	1.9	**9.3**
Total	**282.0**	**287.2**	**292.4**	**298.8**	**305.3**	**1,465.8**

Source: AusNet Services

13.4.4 Revenue adjustments

Consistent with the requirements of clauses 6A.5.4(a)(5) and (5A) of the NER, we have incorporated the amounts that have been determined under the efficiency benefits sharing scheme (EBSS), the capital efficiency sharing scheme (CESS), and the Shared Assets Guidelines. The detailed calculation of each of these components was undertaken in accordance with all applicable provisions of the NER, as explained in Chapter 7 of this Revenue Proposal. Table 13-6 provides a summary of our proposed revenue adjustments.

We note the AER is currently developing a Demand Management Innovation Allowance for transmission networks, which is expected to be finalised prior to the AER's determination for the next regulatory period. Once finalised, this new scheme may have implications for the revenue adjustments shown below.

Table 13-6: Other revenue adjustments ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
EBSS	17.4	8.9	7.5	6.0	-	**39.9**
CESS	1.3	1.3	1.4	1.4	1.4	**6.8**
Shared assets	-1.7	-1.9	-2.2	-2.5	-2.8	**-11.1**
Total	**17.0**	**8.3**	**6.7**	**4.9**	**-1.4**	**35.6**

Source: AusNet Services

13.4.5 Tax allowance

Consistent with the requirements of clause 6A.5.4(a)(4) of the NER, we have incorporated a benchmark tax allowance into our building blocks revenue requirement. The detailed calculation of the cost of tax is explained in Chapter 11 of this Revenue Proposal. The cost of tax calculation accords with the requirements of clause 6A.6.4 of the NER and is summarised in Table 13-7.

Table 13-7: Benchmark tax allowance ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Tax payable	2.8	-	-	-	-	**2.8**
Value of imputation credits	-1.6	-	-	-	-	**-1.6**
Tax allowance	**1.1**	**-**	**-**	**-**	**-**	**1.1**

Source: AusNet Services

13.5 Smoothed revenue requirement

The application of our X-factors in conjunction with our unsmoothed revenue requirement produced our smoothed revenue requirement, as set out in Table 13-8.

Table 13-8: Smoothed annual revenue requirement ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Unsmoothed annual revenue requirement	556.5	523.6	524.2	525.1	517.7	**2,647.1**
Smoothed annual revenue requirement	556.5	542.5	528.9	515.6	502.6	**2,646.1**
X-factor (%)	**0.19%**	**2.52%**	**2.52%**	**2.52%**	**2.52%**	

Source: AusNet Services

Our PTRM attached to this Revenue Proposal demonstrates that the smoothed and unsmoothed revenue requirements are equivalent in net present value terms, as mandated by clause 6A.6.8(c)(1) of the NER.

Clause 6A.6.8(c)(2 requires the X factor to be set to minimise, as far as reasonably possible, the gap between smoothed and unsmoothed revenue in the final year of the regulatory control period. Our PTRM satisfies this clause because our smoothed revenue in 2026-27 is within 3.0% per cent of the unsmoothed revenue for that year.

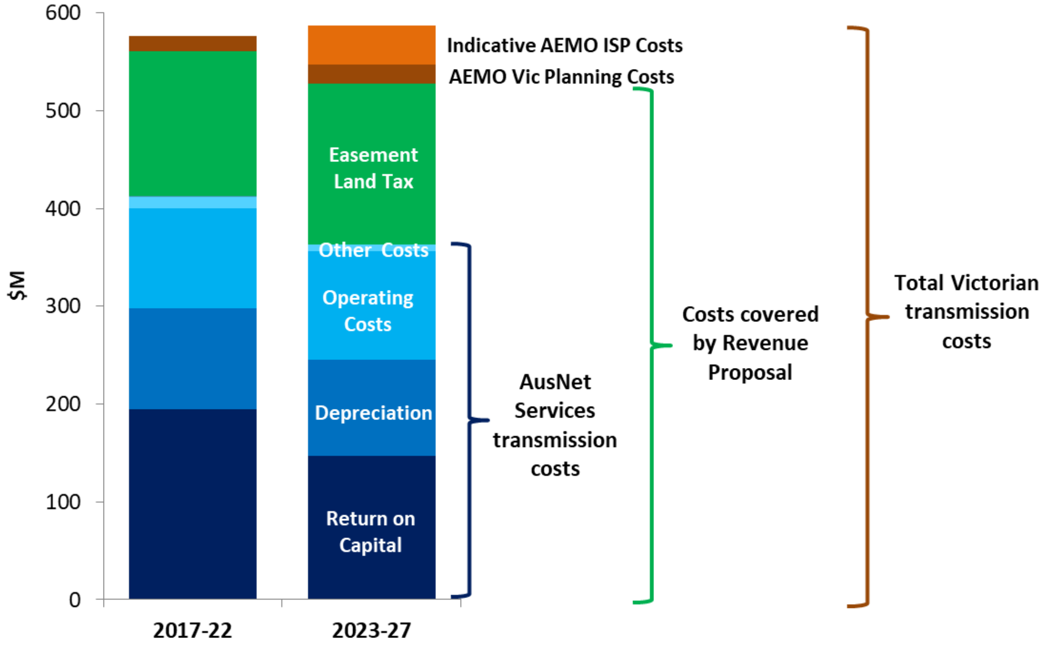
The revenue requirement will be updated annually to reflect:

- Actual CPI, consistent with clause 6A.5.3(c)(3) of the NER;
- The annual return on debt update, in accordance with the AER's *Rate of return instrument* (version 1.02, April 2019);
- AusNet Services' actual service standard performance, relative to its service standard targets, under the Service Target Performance Incentive Scheme; and
- Any approved cost pass-through amount resulting from a pass-through event specified in clause 6A.7.3 of the NER or nominated in Chapter 12 of this Revenue Proposal and accepted by the AER.

13.6 Average transmission charges

AEMO calculates final Victorian transmission charges. As demonstrated by the figure below, these charges will include costs from AEMO Victorian planning responsibilities, and any future costs associated with AEMO's 2020 Integrated System Plan (ISP). Our focus in this Revenue Proposal is to ensure that the costs that are within our control are managed efficiently and prudently in the long-term interests of our customers. The fall in our costs will help offset the future costs of the major transmission upgrades planned for Victoria, which will be included in the total transmission charges that customers will pay.

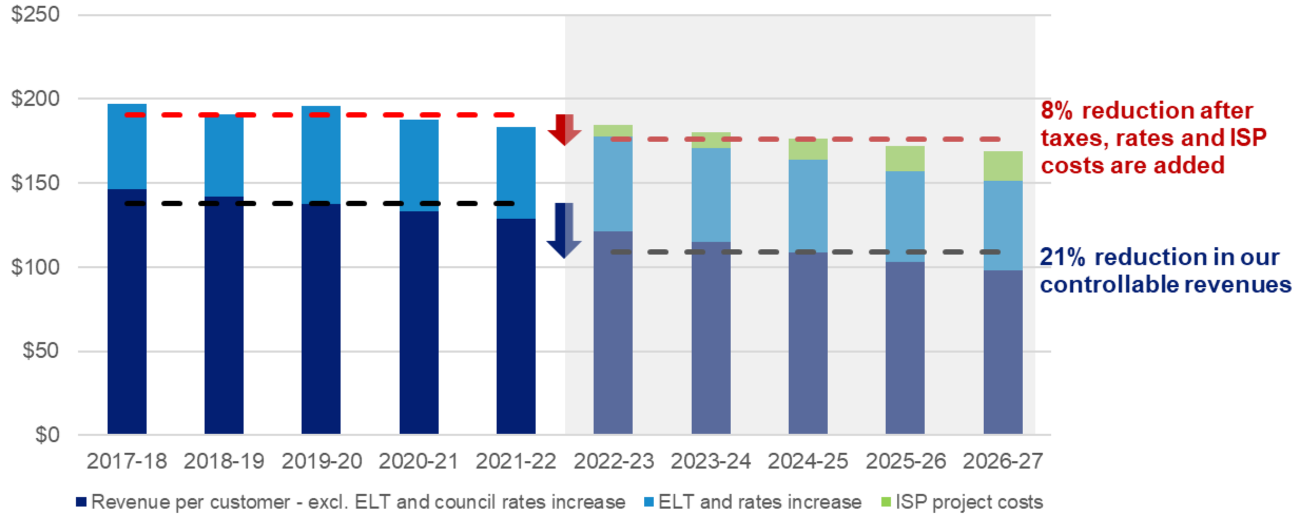
Figure 13-4: Total average annual Victorian transmission revenue by component ($M, real 2021-22)



Source: AusNet Services

As the total number of electricity customers is expected to increase, average revenue per end-use customer for our transmission costs (excluding easement land tax and council rates increases) is forecast to be approximately 21% lower in the 2023-27 regulatory period, falling from $138 to $109 per annum, as shown in the figure below. Including our estimate of future easement land tax and council rates increases, average revenue per customer is forecast to fall by 14%, from $191 to $164 per annum. Adding our estimate of AEMO ISP costs, average revenue per customer is forecast to fall by 8%, from $191 to $176 per annum.

Figure 13-5: Revenue per customer ($ real 2021-22)

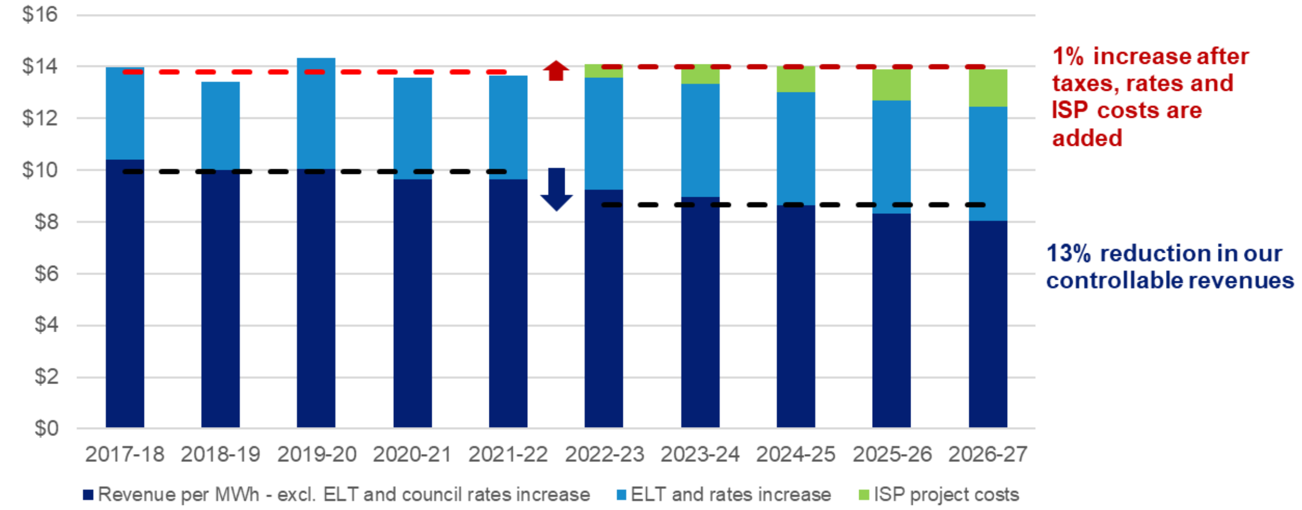


Source: AusNet Services

Note: ISP costs are included for indicative purposes only because it is AEMO, not AusNet Services, that is responsible for procuring and recovering the costs of contestable ISP projects through AEMO's Victorian transmission charges.

On a per MWh basis, revenue is forecast to fall by 13% in the next regulatory period. Including our estimate of easement land tax, council rates increases and AEMO ISP costs, revenue per MWh is forecast to increase slightly.

Figure 13-6: Revenue per MWh ($ real 2021-22)

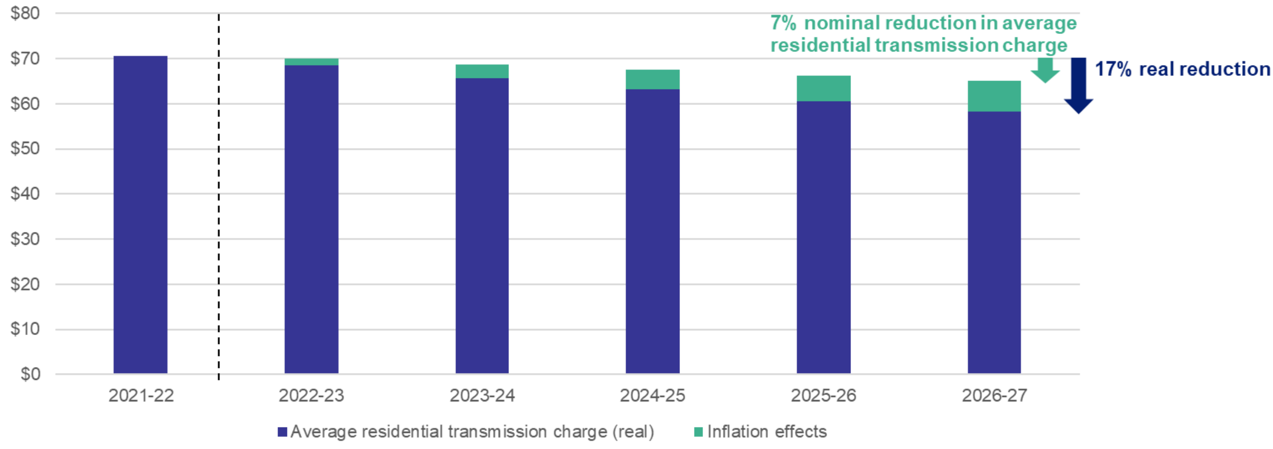


Source: AusNet Services

Note: ISP costs are included for indicative purposes only because it is AEMO, not AusNet Services, that is responsible for procuring and recovering the costs of contestable ISP projects through AEMO's Victorian transmission charges.

For residential customers, and taking account of customer growth, we estimate that our proposal will provide a 7% reduction in the transmission component of the average bill, between 2021-22 and the end of the next regulatory period. Accounting for the effects of expected inflation, our plans provide for a 17% reduction in the transmission component of the average residential bill.

Figure 13-7: Transmission component of average residential customer bill



Source: AusNet Services

13.7 Supporting documentation

We have included the following documents to support this chapter:

- Post Tax Revenue Model;
- Roll Forward Model;
- Standalone Depreciation Model;
- Operating Expenditure Model;
- Efficiency Benefit Sharing Scheme model; and
- Capital Expenditure Sharing Scheme model.

14 Pricing methodology

14.1 Introduction

The NER requires a TNSP to submit a proposed pricing methodology for the prescribed transmission services that are provided by means of, or in connection with, a transmission system that is owned, controlled or operated by that TNSP.

The proposed pricing methodology must satisfy the principles and guidelines established under the NER. Specifically, NER 6A.10.1(e) requires the proposed pricing methodology to:

1. give effect to and be consistent with the Pricing Principles for Prescribed Transmission Services (that is to say, the principles set out in NER 6A.23); and
2. comply with the requirements of, and contain or be accompanied by such information as is required by, the pricing methodology guidelines made for that purpose under NER 6A.25.

NER 6A.24.1(b) describes the purpose of the pricing methodology. It states that the pricing methodology is a methodology, formula, process or approach that, when applied by a TNSP:

1. allocates the aggregate annual revenue requirement (AARR) for prescribed transmission services provided by the TNSP to each category of prescribed transmission services;
2. provides for the manner and sequence of adjustments to the annual service revenue requirement (ASRR);
3. allocates the ASRR to transmission network connection points; and
4. determines the structure of the prices that a TNSP may charge for each category of prescribed transmission services under 6A.23.4(a).

This chapter explains the key features of AusNet Services' proposed pricing methodology. A copy of the proposed pricing methodology is provided as Appendix 15A to this Revenue Proposal. The proposed pricing methodology fully complies with the NER and therefore should be approved by the AER.

The remainder of this chapter is structured as follows:

- Section 14.2 explains the relevance of the Victorian transmission arrangements to the proposed pricing methodology;
- Section 14.3 sets out the key features of AusNet Services' proposed pricing methodology;
- Section 14.4 provides concluding comments; and
- Section 14.5 refers to supporting documents related to this chapter.

14.2 Pricing in the context of the Victorian transmission arrangements

The Victorian electricity transmission arrangements differ from that of other jurisdictions. AEMO and AusNet Services both have responsibilities in relation to the provision of prescribed transmission services in Victoria. These include:

- AEMO providing shared transmission services. For this purpose, AEMO procures network capability and related services from AusNet Services and other TNSPs; and
- AusNet Services providing and offering connection services.

In the context of the pricing methodology, the different responsibilities for providing prescribed transmission services are important. In relation to pricing matters, AusNet Services allocates its

AARR to each of the categories of prescribed transmission services that it provides, and is also responsible for pricing connection services. AEMO is responsible for pricing prescribed transmission use of system (TUOS) services and prescribed common transmission services. AEMO is also the *Co-ordinating Network Service Provider* for Victoria and allocates all relevant AARR within Victoria. In light of the arrangements in Victoria, AusNet Services' proposed pricing methodology only addresses the pricing matters for which AusNet Services has responsibility.

We understand that AEMO will start consulting on its new pricing methodology in the latter half of 2020 and the outcome of the consultation will not be finalised by the time AusNet Services submits its proposed pricing methodology. Whilst we do not expect AEMO's consultation to affect our pricing methodology, we will take account of AEMO's intended new pricing methodology in our Revised Revenue Proposal.

14.3 Key features of the pricing methodology

AusNet Services' *Proposed Pricing Methodology* (Appendix 14A) has been prepared to satisfy the requirements of the pricing principles set out in Part J of Chapter 6A of the NER (as modified by clause S6A.4.2), including:

- Determining the AARR requirement for prescribed transmission services provided by AusNet Services;
- Allocation the AARR to categories of prescribed transmission services provided by AusNet Services to establish the ASRR for that category of service;
- Allocating the ASRR to each transmission network connection point;
- Recovering ASRR as prices in accordance with the principles set out in the NER;
- Detailing information requirements and billing process;
- Explaining the prudential requirements AusNet Services utilises in support of its provision of prescribed transmission services; and
- Setting out the circumstances in which a transmission user may be required to make a capital contribution or prepayment for a specific asset.

In addition, the proposed pricing methodology contains the information required by the AER's Pricing Methodology Guidelines, including a number of hypothetical worked examples to demonstrate how the pricing methodology works in practice.

In light of the respective roles of AEMO and TNSPs in Victoria in relation to prescribed transmission services, the proposed pricing methodology also includes a diagram illustrating the structure of transmission pricing under Part J of Chapter 6A (as modified by clause S6A.4.2) and the respective responsibilities of AEMO and the TNSPs.

14.4 Concluding comments

The NER requires each TNSP to submit a proposed pricing methodology covering its prescribed transmission services and specifies the matters that it must address at the same time it submits its Revenue Proposal. As already noted, the Victorian transmission arrangements differ from other jurisdictions because AusNet Services and AEMO both have responsibility for providing prescribed transmission services.

Our proposed pricing methodology complies with the NER requirements. In addition, it provides additional information in relation to the respective roles of AusNet Services and AEMO. AusNet Services therefore considers that the proposed pricing methodology should be approved by the AER.

14.5 Supporting documents

The following Appendix is relevant to this chapter:

- Appendix 14A – Proposed Pricing Methodology (1 April 2022 – 31 March 2027)

15 Negotiating framework

15.1 Introduction

The NER requires certain transmission services (negotiated transmission services) to be provided on terms and conditions that are negotiated between the TNSP and the service applicant. Negotiated transmission services are a class of service defined in Chapter 10 of the NER. They broadly include services provided in relation to generation or direct connect customer connection to the shared transmission network.

Until July 2018, each TNSP operating in the NEM was required to prepare a negotiating framework, setting out the procedure to be followed during negotiations. However, a rule change determined by the AEMC on 23 May 2017[151] replaced the negotiating framework approach in all NEM jurisdictions other than Victoria. This is because, as stated in the AEMCs determination:

> *The framework under which connections to the transmission network in Victoria occur is fundamentally different to the processes and principles underlying the connection framework used in the rest of the NEM.*[152]

By virtue of NER 11.98.8(a)(1), the negotiating framework approach contained in the version of Chapter 6A that immediately preceded the version of the NER that gave effect to the amending rule continues to apply in Victoria.[153] This is version 109 of Chapter 6A.

The negotiating framework must comply with the minimum requirements specified in NER 6A.9.5(c) (of NER version 109), including requiring:

- The parties to negotiate in good faith;
- The TNSP to provide commercial information to facilitate effective negotiation;
- The TNSP to provide information relating to the costs of service provision;
- Reasonable timeframes for commencing, progressing and finalising negotiations
- A process for dispute resolution;
- Cost recovery arrangements for processing applications and
- The TNSP to notify and consult with any affected transmission users, and to ensure that obligations to those users continue to be met.

The NER[154] also require AusNet Services to conduct negotiations in accordance with the Negotiated Transmission Service Criteria, which will be specified in the AER's final determination. In turn, these criteria must give effect to and be consistent with the principles set out in NER 6A.9.1. In broad terms, these principles establish the acceptable upper and lower bounds for negotiated terms and conditions.

This chapter explains the key features of AusNet Service's proposed negotiating framework. A copy of the proposed negotiating framework is provided in Appendix 16A. AusNet Services is

[151] AEMC, *Rule Determination, National Electricity Amendment (Transmission Connection and Planning Arrangements) Rule 2017*, 23 May 2017.

[152] Ibid, page v.

[153] National Electricity Rules, clause 11.98.8.

[154] Clause 6A.9.4(a)(1).

confident that the proposed negotiating framework complies with the NER and, therefore, should be approved by the AER.

The remainder of this chapter is structured as follows:

- Section 15.2 explains the relevance of the Victorian transmission arrangements to the proposed negotiating framework.
- Section 15.3 sets out the key features of AusNet Services' proposed negotiating framework.

15.2 Victorian transmission arrangements

As explained in Chapter 1, the Victorian electricity transmission arrangements differ from other jurisdictions. In particular, AEMO and AusNet Services both have responsibilities in relation to the provision of transmission services in Victoria:

- AEMO provides shared transmission services. For those purposes, AEMO procures network capability and related services from AusNet Services and other TNSPs.
- AusNet Services provides and offers connection services.

In the context of the negotiating framework, the different responsibilities for providing transmission services are important. A service applicant seeking a negotiated transmission service may need to engage with either AEMO and/or AusNet Services, depending on the type of service sought. In particular:

- A service applicant must negotiate with AEMO for the provision of shared transmission services that are defined as negotiated transmission services.
- A service applicant must negotiate with AusNet Services for the provision of connection services that are defined as negotiated transmission services.

It is also important to note that:

- AEMO has primary responsibility for assessing the impact of a proposed connection on the Victorian transmission network, including its effect on other network users.
- AusNet Services or the relevant TNSP (as applicable) has primary responsibility for assessing and advising a service applicant on the connection assets at the physical interface with its transmission network (network exit services and network entry services).
- Any application to connect to the Victorian transmission network will require the service applicant to enter into agreements with both AEMO for shared transmission services and AusNet Services or the relevant TNSP (as applicable) for connection services.

Accordingly, both AusNet Services and AEMO must have an approved Negotiating Framework, and Frameworks both would be applicable for the majority of connection negotiations. AusNet Services and AEMO recognise that a service applicant seeking a negotiated transmission service may find the Victorian arrangements complex relative to interfacing with a single TNSP as in other jurisdictions and, therefore, potentially confusing. As the principal purpose of a negotiating framework is to establish procedures to facilitate effective and fair negotiation, AusNet Services and AEMO propose a joint Negotiating Framework, as established for the current regulatory control period, to further assist service applicants.

The proposed *Victorian Negotiating Framework* prepared by AEMO and AusNet Services is provided at Appendix 16A.

In addition to complying with the NER requirements, this joint framework explains the respective roles and responsibilities of AusNet Services and AEMO in providing negotiated transmission services.

15.3 Key features of the Negotiating Framework

The joint negotiating framework established by AEMO and AusNet Services addresses all of the matters required in the NER, including:

- Application of the negotiating framework;
- Conduct of negotiations;
- Timeframe for negotiations;
- Costs of investigation and negotiation;
- Charges for negotiated transmission services;
- Provision of information;
- Confidential information;
- Dispute resolution;
- Other network users;
- Suspension of time periods; and
- Termination of negotiations.

In relation to the provision of information to facilitate the effective negotiation, the framework requires:

- Each Negotiating Party agrees to provide to the other Negotiating Parties all such commercial information it may reasonably require to enable that other Negotiating Party to engage in effective negotiation for the provision of the relevant negotiated transmission service.
- A Negotiating Party may give notice to another Negotiating Party requesting any additional commercial information that is reasonably required by the first Negotiating Party to enable it to engage in effective negotiations in relation to the provision of a negotiated transmission service or to clarify commercial information already provided.
- A Negotiating Party who is requested to provide information must use reasonable endeavours to do so within 10 Business Days of the request or as otherwise agreed by the parties.

The Negotiating Framework also ensures that all service applicants are treated fairly by setting out the circumstances in which negotiation may be terminated, including where:

- AEMO or AusNet Services is of the reasonable opinion that the Service Applicant will not acquire the negotiated transmission service.
- AEMO or AusNet Services believes on reasonable grounds that the Service Applicant is not conducting the negotiations in good faith.
- The Service Applicant consistently fails to comply with the obligations in this negotiating framework.

The Negotiating Framework also adopts a dispute resolution process in accordance with Part K of Chapter 6A of the NER (version 109), which provides for the appointment of a commercial arbitrator. These provisions are important in allowing parties access to a timely and effective dispute resolution process should a dispute arise.

The joint Negotiating Framework also notes that it is intended to be capable of adoption by other declared transmission system operators in respect of the connection services they provide in Victoria, subject to AER approval.

AusNet Services considers that the proposed joint AusNet Services and AEMO Negotiating Framework should be approved by the AER.

15.4 Supporting documents

The following Appendix is relevant to this chapter:

- Appendix 15A – Victorian Negotiating Framework.

List of Appendices

Reference	Title
1A	Cost Allocation Methodology
1B	Related Party Arrangements
2A	Asset Management Strategy
2B	ISO 55001 Accreditation
3A	Customer Satisfaction Interviews Summary Report
3B	Deep Dive Summary Report 1
3C	Deep Dive Summary Report 2
3D	Deep Dive Summary Report 3
4A	Unit Rates
4B	Cost Estimating Methodology
4C	ICT Strategy Electricity Transmission Network
5A	Growth Assets
5B	Standalone EPA Step change
5C	5-minute Settlement Quote
5D	BIS Oxford Economics Labour Price Forecasts
7A	Fitting Probability Distributions for Service Component Data
7B	Network Capability Incentive Parameter Action Plan (1 April 2022 - 31 March 2027)
7C	AEMO NCIPAP endorsement letter
10A	Averaging Period Letter
12A	Insurance Certificate of Currency
14A	Proposed Pricing Methodology (1 April 2022 - 31 March 2027)
15A	Victorian Negotiating framework