Jemena Electricity Networks (Vic) Ltd

2026-31 regulatory control period

Expenditure forecasting methodology

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Jemena Electricity Networks
2026-31 Expenditure forecasting methodology

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Glossary

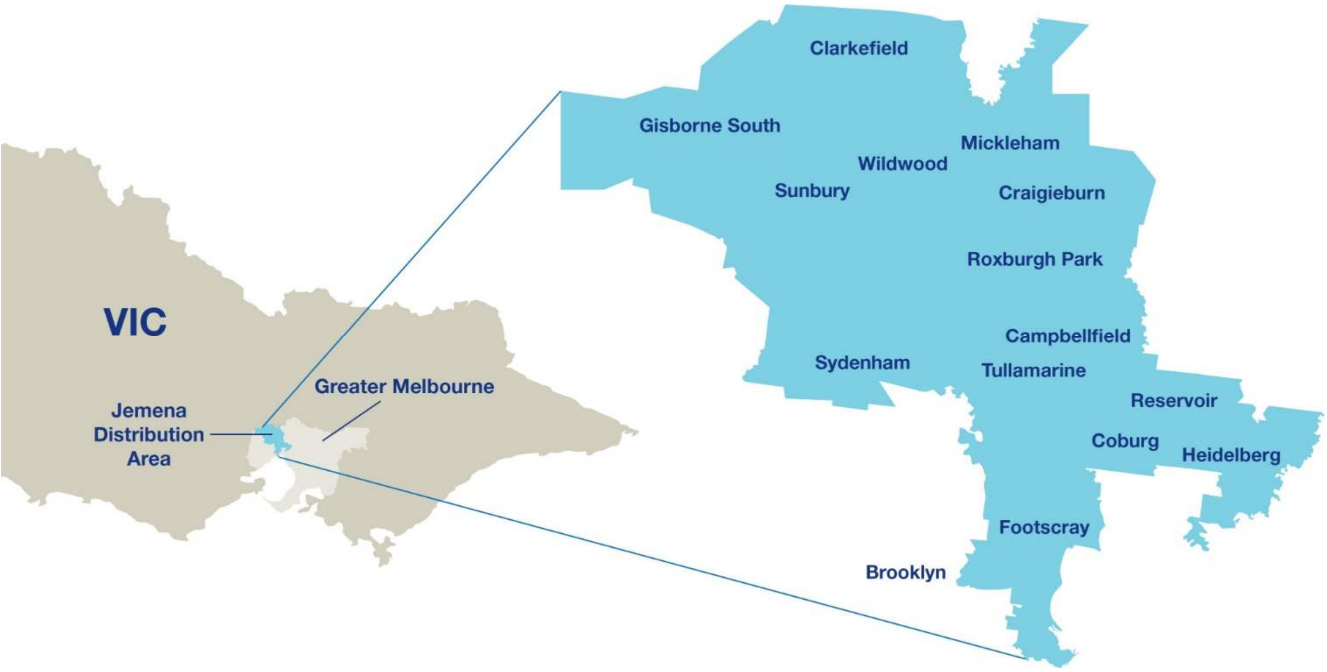
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
CBRM	Condition Based Risk Model
CPI	Consumer Price Index
CER	Customer Energy Resources
ESC	Essential Services Commission
GSL	Guaranteed Service Level
IFRC	International Financial Reporting Interpretations Committee
ISO	International Organisation for Standardisation
IT	Information Technology
JEN	Jemena Electricity Networks (Vic) Ltd
NEL	National Electricity Law
NER	National Electricity Rules
SaaS	software-as-a-service
SCADA	Supervisory Control and Data Acquisition

1. Introduction

Jemena Electricity Networks (Vic) Ltd (**JEN**) is one of five electricity distribution networks in Victoria. We are the sole distributor of electricity in north-west greater Melbourne, and we service more than 370,000 households and businesses.

Our role is to deliver power when our customers need it. We build and manage the infrastructure that transports electricity through more than 950 square kilometres of Melbourne's north-west suburbs, with Melbourne Airport sitting almost in the middle of our patch.

Anyone who is currently connected to the electricity distribution network in our area is a customer of ours. We also connect new customers and provide distribution services to other groups like property developers, landlords, and businesses of all sizes, from sole traders all the way through to large energy consumers such as Melbourne Airport, large data centres and the Austin and Western General Hospitals.



1.1 Background

By 31 January 2025 we will submit a regulatory proposal to the Australian Energy Regulator (**AER**). The AER will assess our proposal as part of the process to set our services and prices for the regulatory control period from 1 July 2026 to 30 June 2031 (**forecast regulatory period**).

In setting our service and prices for the forecast regulatory period, the AER will ensure that we have a reasonable opportunity to recover our efficient costs. As a result, our forecast expenditure for the forecast regulatory period plays a key role in the price-setting process, which is governed by the National Electricity Law (**NEL**) and the National Electricity Rules (**NER**).

1.2 Purpose

Clause 6.8.1A(a) of the NER requires us to inform the AER of the methodology we propose to use to forecast operating and capital expenditure in our regulatory proposal for the forecast regulatory period. This document sets out our forecasting methods.

1.3 Forecasting methodology overview

This document explains the processes and major inputs we will use to develop our capital and operating expenditure forecasts when providing distribution services in the forecast regulatory period. At a high level, this involves three key tasks:

1. understanding and estimating key expenditure drivers, explained in chapter 2,
2. developing a capital expenditure forecast, explained in chapter 3, and
3. developing an operating expenditure forecast, explained in chapter 4.

1.3.1 Expenditure drivers

The first task is understanding and estimating our key expenditure drivers over the forecast regulatory period, including:

1. our customers' expectations, preferences, and requirements for the forecast period
2. how our customers' expectations, preferences and requirements may change over the long term
3. technical, safety, environmental and other obligations we will need to comply with
4. maximum and spatial demand that our network will need to meet
5. number of customers that we will serve
6. amount of electricity that our customers will consume
7. level of reliability, resilience and the quality of supply on our network
8. condition of our assets
9. efficiency improvement opportunities available to us
10. market benefit opportunities that we can facilitate
11. emerging trends in technology and vendor products
12. changes in our input costs
13. trade-offs that we can make between operating and capital expenditure.

1.3.2 Capital Expenditure

The second task is to develop a bottom-up forecast (also referred to as a zero-based forecast) of our capital expenditure for the forecast regulatory period. Different methods are used for different types of capital expenditure.

For example, we use estimation models for regularly recurring expenditures, such as asset replacement, to predict the likely required replacement volumes for certain assets. For some assets, these models may use asset condition or other data to estimate when assets require replacement. We can then estimate the replacement unit cost and multiply this cost by the forecast volume to derive an expenditure forecast.

For less regular capital expenditures, such as network upgrades (augmentation), we develop a forward view of the major projects required over the forecast regulatory period and estimate the costs of these projects on an individual basis.

1.3.3 Operating Expenditure

Our method for forecasting operating expenditure is different from the method use to forecast capital expenditure. At a high level, we will use the AER's preferred 'base, step and trend' approach. This approach involves using actual operating expenditure for the latest full year (called the 'base year') as a starting point for the forecast (or an earlier year if that year is considered more representative of recurrent operating expenditure). In our current process, we will propose this to be financial year 2025 (1 July 2024 to 30 June 2025).

We will then adjust our base year's actual data to account for one-off events and trend these costs to account for forecast network growth, real input cost changes and productivity gains or losses.

We will also identify any major expected step changes to our operating expenditure forecast due to factors not captured in our base year—for example, increases in our forecast operating expenditure as a result of a trade-off with forecast capital expenditure—and develop individual estimates for step changes as part of our operating expenditure forecast.

For the forecast regulatory period, we treat some information communication technology (**ICT**) costs as operating expenditure instead of capital expenditure, consistent with the guidance released by the International Financial Reporting Interpretations Committee **(IFRIC**). This differs from the approach taken in the current regulatory control period where ICT costs were largely classified as capital expenditure.

1.4 Providing feedback

We are currently undertaking a wide range of customer engagement initiatives. If you would like to provide feedback on this document or have your say on your future electricity prices, services, and network, please visit https://GridTalk.com.au/.

2. Expenditure Drivers

We will use the methods outlined in this document to forecast expenditure for the forecast regulatory period. However, we must first understand the drivers which will underpin the need for our expenditure. At a high level, we need to spend money to connect new customers to our network, meet expected demand, and to maintain the quality, reliability, security, and safety of our services. Our key expenditure drivers are explained below.

Engaging with our customers

Responding to our consultation with stakeholders, including our customers, can drive our expenditure. As part of our commitment to ensuring our future plans meet our customers' needs and expectations, we want to better understand their requirements and ensure that we provide services that are in their long-term interests. The way we provide distribution services may evolve as we better understand our customers' requirements, including facilitation of the growing deployment of Customer Energy Resources (**CER**) across our network, this may also affect our expenditure.

Understanding our customers through diverse engagement

As a vital part of our customer engagement, we established six Customer Voice Groups to understand the challenges, priorities, and preferences of a diverse cohort of customers when it comes to the future of energy.

More than 100 customers were part of a dedicated customer group, including specific groups for customers with a disability, seniors, young people, customers from multicultural backgrounds, First Nations Peoples and those experiencing mental health difficulties.

Customers met four times over six months to learn more about our role as an electricity distribution business, the challenges we face and heard from a range of experts. The groups provided input and feedback on a range of topics, including pricing and equity, customer experience, how we support customers experiencing vulnerability and our investments in running the network. Customer feedback will shape the initiatives and expenditure we have in our proposal.

Meeting expected demand

A large amount of our expenditure is driven by the future energy needs of our customers. We must plan, design, and build our network assets to ensure that the needs of our customers can be met today and in the future. The amount of energy our customers use, the time that they use it, whether they generate it themselves and share it, and the location where they use it all significantly shape the nature of our network. We may need to make changes to our network to accommodate these requirements. Customer demand itself is underpinned by several factors including economic and population growth, urban development and consumer and industry trends.

We also connect new customers to our network and must adhere to regulations around how we offer, negotiate, plan, and manage these connections.

Maintaining service reliability and quality

The Essential Services Commission (**ESC**) sets standards for supply quality[1], supply reliability[2] and customer service[3] which we must meet. Maintaining the reliability and quality of our electricity supply becomes more

1 Through the Electricity Distribution Code of Practice, section 20.

2 Through the Electricity Distribution Code of Practice, section 13.

3 Through guaranteed service levels, as set out in section 14 of the Electricity Distribution Code of Practice.

challenging as our network assets age, so, from time to time, we need to spend money to repair, refurbish or replace assets.

Additionally, the economic regulation of our services includes a mechanism (the service target performance incentive scheme) that rewards us for improving the supply reliability of our services and penalises us if our service reliability deteriorates.

Meeting safety, environmental and other regulatory obligations

Various statues, rules and codes set out other obligations which we must meet. The services we provide and the operations we carry out are heavily regulated with regards to safety and environmental obligations, as well as service standards and the prices we charge. The AER, ESC, Energy Safe Victoria, and the Environment Protection Agency are our principal regulatory bodies.

We must spend money to ensure we meet a range of safety and environmental regulations. We must adhere to safety and security standards when we design and undertake work on our assets. We must ensure that vegetation growing near our assets does not pose a safety hazard. We must also comply with various environmental obligations related to vegetation, contaminants, and noise. We also incur costs in meeting our obligations to the AER, including requirements for reporting, preparing a regulatory proposal and network planning reporting (such as distribution annual planning reports and for the regulatory investment test for distribution).

Achieving optimal efficiencies

We seek to identify ways in which we can more efficiently provide our services, ensure we provide services that our customers value the most and ensure the services we provide evolve to be the most efficient mix over the long term. As technology develops over time, new and efficient ways of designing, operating, and monitoring our network, interacting with our customers, and providing our corporate support services will become available, with the potential to benefit us and our customers.

Some external factors outside our control can also make it more costly for us to maintain the reliability and quality of our services. Advances in the development of CER products and services have given customers the ability to generate their own electricity and feed it into our network. In some cases, this can pose challenges for us when designing and managing assets which have historically only transported electricity one way to our customers—not bi-directionally as is the case with CER.

> **Planning for the future of the grid**
>
> As our customers' energy needs rapidly evolve, we must explore new opportunities to ensure we are most efficiently meeting their needs. Increasingly, the emergence of new expenditure drivers—such as ensuring our network has sufficient ability to host exports from small-scale CER while still meeting power quality requirements—will require us to implement new technological solutions to address these new issues. For example, our People's Panel highlighted strong customer expectations that we should enable the increased feed-in of solar and other small-scale renewable generation into the grid.
>
> We therefore actively explore trade-offs between different types of investments (both between different types of capital expenditure and between capital and operating expenditure) to ensure our capital and operating expenditure forecasts reflect an optimal allocation of resources to meet customers' future needs.

3. Capital Expenditure

3.1 Overview of approach

On the most part, we propose to apply a ‘bottom-up’ approach to forecast our capital expenditure for the forecast regulatory period. For a part of our recurrent (ICT expenditure we use a trend approach to forecast this category of expenditure.

The starting point of our bottom-up cost build is developing project and program plans for our network and non-network assets. Examples of these include:

- asset replacement projects
- network upgrade and modification projects
- customer-initiated projects

We prepare these project and program plans in the usual course of business planning, detailing the investment required for us to continue to provide distribution services into the future. These project and program plans draw on information provided by our customers about their expectations and requirements, as well as information maintained in our internal asset management databases relating to our assets. The information we use when developing project and program plans includes:

- forecast demand for our services
- asset quantities, location, type, and age
- asset condition (test and audit data)
- asset ratings and utilisation rates
- network outage data and other performance data
- detailed project, contractor, and work activity cost estimates.

The individual project and program plans each apply their own fit-for-purpose forecasting methodology used in our usual course of business but are continually updated and improved to reflect changing market factors and investment drivers. Further detail on our individual forecasting methodologies is provided in section 3.2.

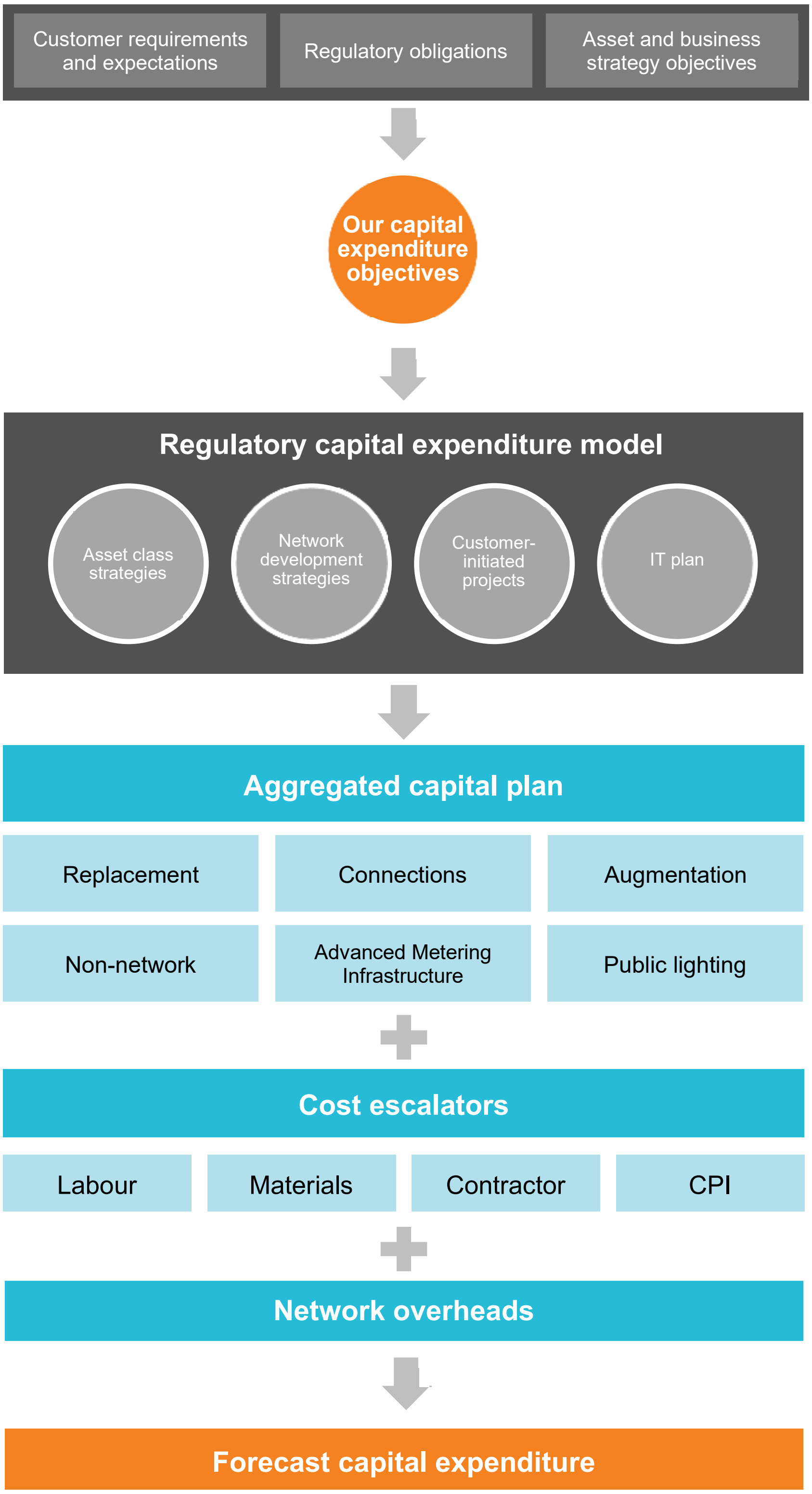
For the purposes of this proposal, we undertake a specific approach to forecasting ICT capital expenditure. For expenditure that is recurrent in nature we take the average historical expenditure and trend it forward; for non-recurrent expenditure,[4] we develop bottom-up business cases. Further detail on our individual forecasting methodologies is provided in section 3.2.4.

The project and program plans are then fed into our regulatory capital expenditure model, where they are combined into a single capital plan for the forecast regulatory period. At this stage, the required projects are itemised and prioritised, and expenditure is mapped to the required regulatory cost categories. We also apply inflation and cost escalators to account for changes in labour, materials, and contractor costs. Finally, we apply network overhead costs, where appropriate, to derive our total forecast capital expenditure.

This process is summarised in Figure 3–1 below

[4] Typically new systems or systems that incur expenditure on a longer term cycle basis.

Figure 3–1: Our capital expenditure forecasting method



3.1.1 Quality assurance of Governance framework

Jemena completes annual surveillance and triennial certification audits for certification to ISO 55001[5] (asset management) standard. This reflects international best practice in asset management and demonstrates prudent and efficient decision-making.

Our quality assurance and governance frameworks mean that all projects and programs—even in the medium to longer-term forecasts—require extensive analysis, documentation, and peer review before they are included in our capital plan. We are therefore confident that our project and program plans and expenditure forecasts are likely to reflect the expected costs needed to manage our assets in accordance with industry best practice.

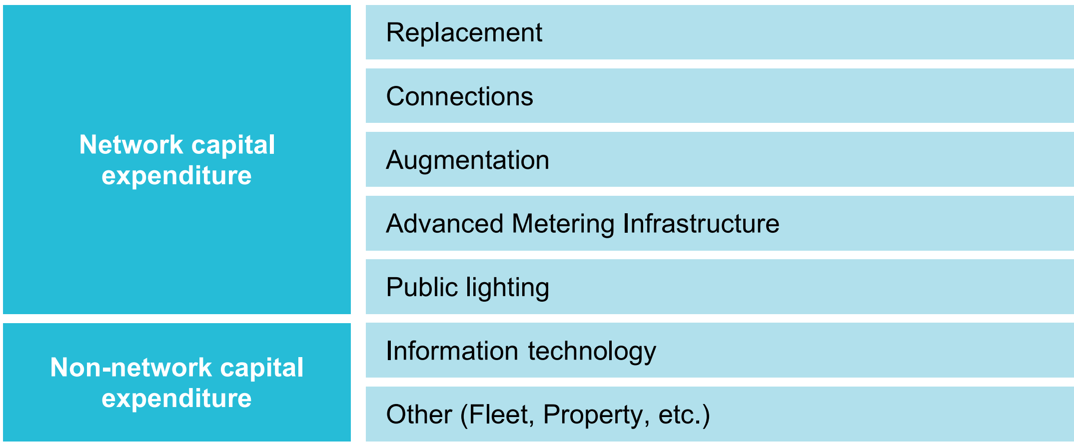
3.2 Bottom-up forecasting approaches

This section explains the nature of the expenditure and the underlying forecasting methodology for each of the following capital expenditure categories:

- replacement
- connections
- augmentation
- non-network—information technology[6]
- non-network—other
- advanced metering infrastructure (**AMI**)
- public lighting.

Figure 3–2 presents a classification of forecast capital expenditure by regulatory cost categories.

Figure 3–2: Capital expenditure categories



3.2.1 Replacement capital expenditure

Replacement capital expenditure is required to maintain the level of performance provided by our existing assets. The drivers for replacement capital expenditure include deterioration in the condition of an asset or its environment and where increases in maintenance costs mean it is more cost-effective to replace an ageing asset than continue to maintain it. We also undertake consequence-based replacement, where we undertake a thorough assessment of 'needs' to determine whether a lower-rated asset could satisfy a requirement rather than blanketly apply a like-

5 ISO 55001 Asset management – Management systems – Requirements, published by the International Organization for Standardisation.

6 Including trending recurrent ICT capital expenditure.

for-like replacement. Also, capital expenditure for SCADA and network control is also forecast using the methods outlined in this section.

We manage and plan asset replacement by grouping our assets into a set of classes, for which we develop project and program-level forecasts. These asset classes can be further grouped into the following categories:

- low volume/high-cost assets—where we know or can estimate information on the condition or performance of a specific asset, we can predict the need to replace it and then identify appropriate solutions; and
- high volume/low-cost assets—where it would be cost prohibitive to identify and analyse individual future asset requirements, we use simplified approaches to produce aggregate forecasts for an asset population.

For several critical assets, we develop a condition-based risk model (**CBRM**) to support the evaluation described above. CBRM is a risk-based model that generates an asset health index and ageing rate. This is used to estimate a probability of failure and a range of future failure rates depending on the intervention measures we may choose to take.

> **Condition and consequence-based asset replacement**
>
> When developing our asset replacement forecast, we take into account not only the condition of our assets, but also the consequences in the case that they were to fail. This ensures that our replacement expenditure is only the amount necessary to continue supplying customers based on their current and likely future requirements.
>
> For example, large transformer replacement is managed via a condition-based replacement program. Assets are inspected and if a condition assessment indicates replacement is required, such a replacement is programmed to be completed. In deciding what rating distribution transformer to install as the replacement unit, CER is also taken into consideration (i.e., amount of solar export in the area).

3.2.1.1 Forecasting approach

For low volume/high-cost assets, we prepare forecasts based on our business-as-usual planning processes. Information about specific assets (such as asset test or audit data, asset performance data or condition-based data) is used to assess the need to replace individual assets. If we identify a need, we develop and evaluate replacement options. We then develop a cost estimate for each option given the scope of works and relevant unit cost schedules for those options.

For high volume/low-cost assets, the techniques we use to develop program-level forecasts can be broadly classified as one of the two approaches summarised below:

Recurrent programs

We prepare forecasts for recurrent programs (for example, the condition-based replacement of poles) using different methods depending on the circumstances. Two such methods include:

- using predictive models, for example, CBRM or methods similar in philosophy to the AER's replacement capital expenditure model, to estimate a future trend in the volume (or expenditure) of ongoing programs based on asset information such as age and distribution of failure
- using historical trends (either of volume or expenditure) for some smaller programs, where it is not considered appropriate to develop more complex forecasting models (given the benefits and costs of obtaining a more accurate forecast). For some assets, we only replace when failure has occurred.

Special-purpose programs

We use these programs to address a specific need, such as when an asset (or class of assets) begins to exhibit a safety or performance issue. A forecasting approach similar to that of low volume/high-cost assets is employed.

3.2.2 Connections capital expenditure

Customer connections capital expenditure is required to plan and construct new customer connections and upgrade existing customer connections. We undertake this work upon the request of customers and real estate and property developers.

The nature of connections activities and expenditure is unique compared to most other expenditure categories, and this uniqueness poses challenges for preparing short, medium, and longer-term forecasts, as:

- connections are a reactive activity that are only undertaken in response to customer requests
- the volume of work is primarily driven by external factors (for example, economic activity)
- there is a wide variation in customers' requirements, and therefore connection project types and costs.

For the majority of our connection expenditure, we use an economic modelling approach to produce a forecast of total connection volumes and expenditure. This approach links movements in certain economic indicators forecast by expert consultants, to connection activity levels.

3.2.2.1 Forecasting approach

The forecasting model used for connection expenditure can be separated into two elements:

- Annual expenditure forecasting—we use this approach to construct a relationship between our historical annual expenditure and economic explanatory variables. These relationships are used to develop 7-year annual expenditure forecasts.
- Annual activity volume forecasting—we use this approach to produce annual activity volume forecasts. We do this by applying historical volumes to an annual expenditure forecast and then seasonalising the forecast.

We use each of these elements as inputs to our connections model to derive our forecast connections. Additionally, we will produce bottom-up forecasts for large customer connection projects based on specific information from these customers about their individual requirements.

3.2.3 Augmentation capital expenditure

Augmentation expenditure is required to ensure our network can meet customer and regulatory requirements for network capacity, quality of supply and network safety. Typically, this category of expenditure is driven by changes in our customers' maximum demand for electricity; however, other augmentation expenditure drivers are becoming increasingly prevalent, for example, providing sufficient hosting capacity to accommodate an increase in energy exports from small-scale CER as well as accommodating for forecast uptakes in electric vehicles and managing the effect of this on peak demand.

We employ a proactive planning approach for our sub-transmission lines, zone substations and high-voltage feeders. We use customer number and demand forecasts, historical trend data and direct consultation with large customers to understand whether customers will require extra network capacity in the future—as we must augment network capacity in anticipation of any increased demand occurring.

For distribution substations and low-voltage circuit augmentation, we consider both proactive and reactive approaches. We employ analysis and load testing of the network to proactively identify areas that require augmentation in order to mitigate imminent reliability and power quality issues. Reactive augmentation of the network is also undertaken to resolve network issues typically identified during periods of peak demand.

3.2.3.1 Forecasting approach

Our forecasting approach to augmentation expenditure involves several stages of technical and economic analysis. This analysis predicts and evaluates emerging constraints on the transfer of electricity in our network. Although augmentation capital expenditure has historically been driven by forecasts of maximum demand, factors other than maximum demand are increasingly driving augmentation expenditure.

Key inputs and assumptions in our augmentation expenditure forecasts include (but are not limited to):

- spatial peak demand forecasts
- customer demand assumptions
- embedded generation assumptions, including their impact on network power quality
- modelling of contingent events
- value of customer reliability.

> **Spatial peak demand forecasts**
>
> Typically, network constraints occur during times of peak demand (peak demand refers to the maximum amount of electricity used by customers at any time). Forecasts of peak demand are therefore a key input to forecasting our augmentation expenditure. Spatial peak demand forecasts are prepared for smaller geographic areas of our network and are reconciled to network-level peak demand forecasts.

3.2.4 Non-network—Information technology capital expenditure

Our non-network information technology capital expenditure forecast is developed to:

- manage and maintain our ICT capabilities with a balanced approach to the cost and acceptable level of risk
- ensure ICT capabilities are sustainable and reflect good industry practice
- leverage new technologies to improve operational efficiency and effectiveness.

To prepare our ICT platform and operations for the forecast regulatory period, we consider current and future state trends. To this end we:

1. plan and cost the asset lifecycle for each ICT asset in terms of augmentation, market growth, systems upgrades and end-of-life replacement
2. analyse changes in the business and the state of inflight projects and consider opportunities to leverage new capabilities
3. engage to capture future state capability requirements that reflect customers' expectations and requirements and the direction of the business

4. conduct risk-based evaluations of the ICT solutions that support business operations (for example, system upgrades), taking into account vendor roadmaps, support costs, ongoing maintenance costs and industry trends
5. investigate the use of new technologies that can deliver greater benefits to the business and its customers
6. develop cost estimates using a combination of one or more of the following: historical financial information based on similar system deployments, vendor estimates, anticipated resourcing and / or benchmarking.

When forecasting the expenditures involved in delivering the ICT architecture, we adopt the approach outlined in the AER's ICT expenditure forecasting assessment approach.[7] Using this framework, we develop capital expenditure forecast proposals based on two categories:

- Recurrent capital expenditure – this category of forecast expenditure is determined by taking the five-year average recurrent capital expenditure that arises within the current period. The forecasting approach works on the assumption that this type of expenditure occurs on a cyclical (recurrent) basis, with cycles occurring between one and five years.
- Non-recurrent capital expenditure – this category of forecast capital expenditure occurs on cycles of more than five years or has not previously occurred. The approach to forecasting projects that have non-recurrent capital expenditure is based on a build up of cost estimates as outlined above.

3.2.5 Non-network—other capital expenditure

Our capital expenditure in the non-network—other category predominately comprises the following items:

- vehicle fleet
- property and buildings
- tools and equipment.

Vehicle fleet

Vehicle fleet capital expenditure is forecast in accordance with our fleet asset class strategy—a strategic plan that sets out how and when we maintain and replace vehicles, to ensure they operate safely and are fit for purpose. Vehicles forecast due for replacement (following assessment of their condition) are obtained in accordance with our procurement policy. We may also need to augment our fleet by purchasing additional assets on an as-needed basis—expenditure on new fleet assets is supported by a business case and undertaken in accordance with our procurement policy.

Property and buildings

Our capital expenditure on property and buildings is forecast using bottom-up cost builds, as supported by business cases.

Tools and equipment

Capital expenditure for our tools and equipment is forecast in accordance with our general tools and equipment strategy. This strategy sets out the equipment lifecycles for different assets. Capital expenditure on new and replacement tools and equipment is forecast on a 5-yearly rolling plan, with unit costs obtained in accordance with our procurement policy.

[7] AER, *Non-network ICT capex assessment approach*, November 2019.

3.2.6 Advanced metering infrastructure capital expenditure

Our capital expenditure forecast for AMI includes the following activities:

- replacing end-of-technical life and defective meters and communication equipment
- taking account of the demand for 3-phase meter upgrades due to greater electrification
- upgrades of systems to maintain performance and supportability of services (including complying with new market requirements)
- installing meters for new and upgraded customer connections
- maintaining communication systems to service new customers
- introducing new meter types into our meter base as new, efficient technologies become commercially available
- upgrading the software and hardware that supports metering systems.

3.2.6.1 Forecasting approach

We will utilise a bottom-up cost build by activity to forecast our AMI capital expenditure. Activity volume forecast inputs to our AMI capital expenditure forecast include historical trends and customer number forecasts, and we also take into account compliance obligations such as meter specification, meter installation inspection and market settlement requirements. As with the other capital expenditure methodologies, we apply unit costs to forecast our AMI capital expenditure, using the same approach as with other network assets.

3.2.7 Public lighting capital expenditure

Public lighting capital expenditure is required to replace existing public lighting assets (such as light fittings, brackets, dedicated public lighting poles and cables), which have reached the end of their useful life and are no longer serviceable. In some cases, public lighting also requires replacement with modern equivalents to comply with government policies, such as those relating to the use of mercury in lights, when a light type becomes obsolete and can no longer be maintained or when vendors no longer supply certain types of luminaires.

As new public lighting and alterations to existing lighting assets are fully funded by the requesting public lighting customer, our capital expenditure allowance only includes expenditures relating to the replacement of these assets. Capital expenditure to augment public lighting assets is therefore not covered by this document.

We forecast public lighting capital expenditure using methods similar to those described above for replacement capital expenditure, such as predictive models and historical trends.

4. Operating Expenditure

4.1 Introduction

We intend to use a 'base, step and trend' approach to forecast our operating expenditure for the forecast regulatory period. Our approach aligns with the AER's preferred approach to forecasting most categories of operating expenditure, as outlined in the AER's expenditure forecast assessment guideline. For those remaining costs (such as debt raising costs, guaranteed service level payments, we intend to use a specific or bottom-up forecasting approach that better reflects the nature of these costs.

This chapter first describes our key operating expenditure categories for standard control services and then steps through our intended forecasting approach.

4.2 Base, step and trend forecasting approach

We will employ the base, step, and trend approach to forecast most our operating expenditure for standard control services and for type 5 and 6 (including smart metering) services. This forecasting approach is consistent with the AER's expenditure forecast assessment guideline[8]. We will forecast operating expenditure for all other services on a bottom-up build basis.

Under the base, step and trend approach, costs are forecast using four broad steps:

- **Step one:** identify an efficient base year, based on our current and historical costs
- **Step two:** adjust this base year for non-recurrent expenditure, including changes in accounting standards
- **Step three:** trend the base year forward over the forecast regulatory period, taking into account expected changes in network scale, real input costs such as labour and materials, and productivity gains
- **Step four:** add or remove costs related to external factors outside of our control and any expected step changes in costs not reflected in our base operating expenditure.

Each step is explained in further detail below and is summarised in Figure 4–1.

Figure 4–1: Base, step, and trend approach

4.2.1 Our base year

We intend to use the 2025 financial year (1 July 2024 to 30 June 2025) as the efficient base year, given it will be the latest actual expenditure data available when the AER makes its final determination for JEN. As we have consistently underspent below our efficient operating expenditure allowances, responding to the incentives provided by the regulatory framework (including the Efficiency Benefit Sharing Scheme) over a number of years, our actual operating costs from our base year represent the baseline from which a forecast of the prudent and efficient operating expenditure can be calculated.

We intend to adjust the base year operating expenditure to remove non-recurrent costs.

8 Australian Energy Regulator, *Better Regulation: Expenditure forecast assessment guideline for electricity distribution*, August 2022, cl. 4.

We intend to trend the base year forward to account for changes in:

- **network scale**—due to expected changes in customer numbers, circuit length, ratcheted maximum demand and other relevant factors, changes in our activity levels may be required
- **real input costs**—due to expected changes in labour, the cost of the inputs we use may change over time
- **productivity**—due to developments in technology and other factors, changes in our productivity may arise.

In some cases, we intend to engage experts to estimate expected changes in these cost drivers.

4.2.2 Step changes

We intend to add step changes—which can be positive or negative—to account for expected changes in the recurrent operating expenditure. External factors include regulatory obligations, legislative impacts, or outcomes from customer engagement, which may affect expected service levels. We may also include operating expenditure step changes that result from efficient trade-offs between capital and operating expenditure (for example, where demand management is used as a substitute for capital investment), where these are not captured in our efficient base year or trend escalation. We intend to use a bottom-up method to forecast the impact of step changes.

4.3 Other forecasting approaches

Although we intend to use the base, step and trend approach for most standard control service operating expenditure costs, there are some exceptions where alternative approaches will be used.

Table 4–1 describes these alternatives for some standard control services operating expenditure categories and explains why they are preferred to the base, step, and trend approach in each case.

Table 4–1: Alternative operating expenditure forecasting approaches – standard control services

Category	Forecasting approach	Why this approach is preferred to base, step and trend
Debt raising costs	These will be measured in basis points, which will be multiplied by the benchmark level of debt at the start of a year to determine the debt-raising costs for that year.	This method is consistent with the AER's Post Tax Revenue Model handbook for distribution network service providers which requires benchmark debt raising costs and is consistent with previous regulatory determinations by the AER for distribution network service providers.
Licence fees	Forecast on a specific basis, taking into account other available mechanisms for cost recovery of JEN's distribution licence fee.	The Victorian Minister sets this cost for Finance and is not affected by the same trends accounted for in the base, step and trend forecasting approach.
GSL payments	Forecast based on historical averages for GSL payments made in the previous regulatory period.	These costs are not affected by real input cost or productivity changes as they are set within the Victorian electricity distribution code of practice.
Non-network alternatives	Forecast on a case-by-case basis after assessing the net present value of each project in a similar way to the forecasting approach used for our capital program.	This expenditure is justified by outcomes, such as efficiently addressing an identified network constraint, and is not accounted for in the base, step and trend forecasting approach.

5. Links between Capital and Operating Expenditure forecasts

We intend to develop our capital and operating forecasts consistent with each other, including taking account of any interactions between the two. Interactions between our capital and operating expenditure forecasts may include:

- reflecting changes to operating expenditure due to any efficiencies which result from changes in our capital expenditure
- ensuring that consistent inputs are reflected in both our capital and operating expenditure forecasts, such as expected network scale and real input cost changes
- ensuring that costs are not double counted in, or excluded from, both our capital and operating expenditure forecasts
- addressing changes to accounting standards.

6. Forecasting notes

This forecasting methodology has been drafted with the most up to date information and is current as at submission. It should be noted that over the regulatory period updates may be required to cater to the dynamic nature of the market and changes to regulatory and accounting requirements.