ERGON ENERGY NETWORK

Part of Energy Queensland

Expenditure Forecasting Methodology

2025-30

June 2023

Contents

1 INTRODUCTION

This Expenditure Forecasting Methodology outlines the methodologies that Ergon Energy Network (Ergon Energy) proposes to use to prepare the operating expenditure (opex) and capital expenditure (capex) forecasts in the 2025-30 regulatory proposal that will be submitted to the Australian Energy Regulator (AER) in January 2024. This document has been prepared for submission to the AER as required under clause 6.8.1A of the National Electricity Rules (NER).

The purpose of this document is to inform stakeholders about Ergon Energy forecasting methodologies, prior to Ergon Energy submitting our regulatory proposal to the AER.

1.1 Our engagement with customers

In developing our 2025-30 Regulatory Proposal, we have built upon our existing business-as-usual engagement activities to ensure ongoing effective, genuine and authentic engagement with customers and stakeholders throughout Queensland. Together with the insights provided by our customers and stakeholders through our past and current engagements, we will ensure that additional insights from our specific 'regulatory proposal' engagements will collectively inform and help shape our proposal. This will ensure our business strategy, investments, and operations for the 2025-30 regulatory period and beyond, reflect the wider voice of our customers and communities and take account of what matters most to them in the provision of electricity distribution services.

This Expenditure Forecasting Methodology will be published at www.talkingenergy.com.au. Questions about this document should be sent to RDP2025Connect@energyq.com.au or submitted via www.talkingenergy.com.au.

1.2 About our network

Ergon Energy Network manages an electricity distribution network which supplies electricity to over 750,000 residential homes and commercial and industrial businesses. Taking supply from the Queensland Transmission Network Service Provider Powerlink, we provide electricity across a vast operating area of over one million square kilometres – around 97 per cent of the state of Queensland, with a maximum demand of around 2,600 MW and delivering around 13,700 GWh per year.

Our electricity network consists of 145,000 kilometres of overhead powerlines, 9,400 kilometres of underground power cables, one million power poles, 262 zone substations, 37 bulk supply substations and 98,000 distribution transformers. Based on line length, around 70 per cent of our electricity network runs through rural Queensland, typically with large distances between communities and one of the lowest population densities per network kilometre in the National Electricity Market. We have a proportionately high investment in sub-transmission assets compared to the more urban network, with voltage levels including 230V, 11kV, 22kV, 33kV, 66kV and 132kV. We also have one of the largest Single Wire Earth Return networks in the world.

2 OUR INVESTMENT DRIVERS, APPROACH AND INPUTS

The aim of our expenditure is to safely deliver sustainable, reliable, affordable and equitable energy solutions to our customers and communities. Our focus over the forthcoming period is to deliver:

- Sustainable investment to avoid the historical boom-bust cycle and manage aged assets, while seeking continued cost efficiencies;
- Improved community and staff safety, by leveraging innovative solutions to transition to an intelligent grid and manage asset safety risks and severe weather events; and
- Investments that enable and leverage the availability of distributed energy solutions – including both grid scale and small solar generators, electric vehicles, and energy storage solutions.

2.1 Drivers of Expenditure

The majority of our expenditure is dedicated to building, maintaining, operating and replacing electrical assets. The key drivers of this expenditure are listed below:

- Connecting customers;
- Security, performance and reliability needs of customers;
- Actively managing vegetation near our electrical assets;
- Maintaining assets to ensure that they are operating safely and efficiently over their lifetimes;
- Transitioning to an intelligent grid capable of meeting customers' future needs, including the enablement of export services and maintaining power quality in a changing energy environment;
- The ongoing need to operate, evolve, adapt and scale the systems and tools used to efficiently run our business, to deliver services to our customers and enable the customer led electricity industry transformation.; and
- Competitive alternatives including non-network solutions.

Our expenditure forecasts reflect these drivers through an efficient mix of capex and opex to manage overall network risk.

2.2 Investment Approach & Governance

Ergon Energy is part of a public, unlisted company, with two shareholding Ministers who hold the shares on behalf of the State of Queensland. The Board has reporting and continuous disclosure obligations to the shareholding Ministers under the *Government Owned Corporations Act 1993* (Qld) (GOC Act) and *Corporations Act 2001*. Central to our governance process is compliance with legislation. The GOC Act requires the submission of a Corporate Plan (CP) and Statement of Corporate Intent (SCI).

A four-tier governance process exists to oversee the investments we make in the distribution networks.

1. **Asset Management Strategy & Policy**: Alignment of future network development and operational management with Energy Queensland strategic direction and policy frameworks to deliver best practice asset management. This guides operational plans and work to implement the strategy.

2. **Investment Plan**: Development of seven year rolling expenditure programs and a 12-month detailed program of work, established through the annual planning review process, to ensure:
    - Fulfilment of compliance commitments.
    - The network risk profile is managed and aligned to the corporate risk appetite and
    - Oversight of the approval of the annual network Programs of Work and forward expenditure forecasts.

3. **PoW Performance Monitoring**: EQL has specific corporate Key Result Areas (KRA) to ensure the PoW is being effectively delivers and ensure performance standards and customer commitments and financial program performance is overseen by senior management through the monthly Works Program Committee (WPC) to ensure optimal outcomes with appropriate balance between governance, variation impact risks, emerging risks, and efficiency of delivery.

    A comprehensive program of work scorecard is prepared monthly, and key metrics are included in the Program of Work Delivery Index, which is a corporate key performance indicator that, with monthly performance reporting for key projects, informs the Executive and Board. Quarterly Program of Work updates are provided to the Board.

    We report asset safety performance, including a review of asset related safety issues and emerging asset safety risks, monthly to the Energy Queensland (EQL) Board and our Executive Committee, and quarterly to the People, Safety and Environment sub-committee of the Energy Queensland (EQL) Board. We also report quarterly to the EQL Board on the progress of major projects and programs in our program.

4. **Project and Program Approval**: Individual projects and programs are overseen by executive and senior management and are subject to an investment approval process requiring business cases to be approved by an appropriately authorised financial delegate. EQL has in place a Governance and Delegations Policy which is underpinned by a Register of Delegations. Delegations are assigned to positions rather than to individuals. Table 1 depicts the delegation limits which apply to financial commitments to spend in relation to regulated or unregulated projects.

    Any project above the CEO delegation must be approved by the EQL Board and may also require notification to or approval by the shareholding Ministers, with such notification or approval dependent upon thresholds set out in the Governance and Delegations Policy and required within the Investment Guidelines for GOCs. Further, the development of programs and projects is undertaken by EQL's PoW Development & Review Forum and is compliant with relevant EQL policies, protocols and standards.

Table 1 – Energy Queensland Register of Delegations

Delegation	Shareholding Ministers	EQL Board	Chief Executive Officer	Executive General Managers	General Managers
Financial commitment approval	> $100m	$100m	$50m	$20m	$5m

2.3 Opex-capex trade-offs

The benefits that flow from prudent and efficient capex include minimising current and future electricity costs, having a safe network with modern assets, increased performance and lowering maintenance costs. Ergon Energy systematically considers the trade-offs between opex and capex by considering/reviewing:

- Design and maintenance standards;
- Decisions to renew, replace or maintain assets;
- Equipment specification and purchasing;
- Investment in assets that will function in the expected longer-term climate change scenarios and are appropriate for the challenging Queensland operating environment; and
- Demand management programs including the application of the Regulatory Investment Test for Distribution (RiT-D) in seeking non-network and competitive alternatives to network-based capital projects.

These approaches ensure that an efficient trade-off between opex and capex has been considered at both an individual component level (e.g. equipment specification), a project level (e.g. replacement decisions) and a network level (e.g. our demand management programs).

2.4 Key inputs

The key inputs used in developing our expenditure forecasts are summarised in Table 2.

Table 2: Key Inputs

Item	Description
Customer engagement	The outcomes of the engagement program are used as an input to provide details on customer expectations regarding level of service, reliability and investment.
Demand, energy and customer volumes	The base-case network peak demand forecast is used to forecast network augmentation capex and a base-case customer volume forecast is used to forecast connections and customer initiated capital works. Customer volumes and demand are used to inform the opex forecasts. It is expected that actual maximum demand, energy and customer connection growth will not vary materially from forecasts.
Customer connections	In addition to the impact that customer volumes have on the demand and energy forecasts, the new connections that customers request form an important part of our expenditure forecast. This includes both load and export customers.
Export Services	The recent change to the National Electricity Rules on export services has resulted in an additional category of expenditure for us to incorporate into our expenditure forecasts.
Base year (opex)	The financial year 2023-24 has been selected for use as the base year for the opex forecast as it is expected to reflect the most relevant and up-to-date expenditure information at the time of the AER's final decision.
Cost escalators	Cost escalators are applied to reflect changes in labour and contractor costs. An independent expert will forecast appropriate escalation rates.
Forecast inflation	Inflation will be forecast using short term forecasts from the Reserve Bank of Australia's (RBA's) statement of monetary policy and then the midpoint of the RBA's target inflation range.
ICT	Growth in the use of intelligent devices, growth in the volume and sophistication of cyber events/threats/risks and growth in interconnected systems across energy ecosystems is creating larger 'attack' surface areas. These inputs have necessitated an uplift in cyber capabilities to monitor, detect and respond.
Unit rates and project estimates	Unit rates and project estimates are used to develop bottom-up forecasts where appropriate. An independent expert will be engaged to provide advice and review unit rates to advise whether these are reasonable and reflect prudent and efficient operations.
Asset information and Network Performance Data	A combination of age, condition, and performance history is used to inform asset-related risk and develop programs of work that manage risk to tolerable levels with a focus on safety, legislated requirements and customer impacts.
Safety Obligations	The *Electrical Safety Act 2002* (Qld) (Safety Act) and *Electrical Safety Regulation 2013* (Qld) (Safety Regulation) provide the legislative framework for electrical safety in Queensland and are administered by the Electrical Safety Office (ESO). The fundamental principle of the legislation is to set legal requirements to ensure the electrical safety of licensed electrical workers, other workers, licensed electrical contractors, consumers, and the general public.
Distribution Authority	The Distribution Authorities include sections that set minimum service levels through a combination of the Minimum Service Standard, Safety Net and Improvement Program (also known as Worst Performing Feeders Program).
Network Transformation Opportunities	New innovations, systems, tools or products that demonstrate the potential to change the way we plan, operate and maintain our network and provide services to customers. Examples include non-network solutions, LiDAR and Demand Side Response.

3 OPERATING EXPENDITURE

This section explains the methods that Ergon Energy proposes to use to forecast our efficient opex for the next regulatory period. It explains:

- the opex categories, and
- the specific forecasting method to be applied for each opex category.

3.1 Opex categories

We are required to present our opex forecast for Standard Control Services (SCS) in six categories for the purpose of the AER's Category Analysis and Reset Regulatory Information Notice (RIN) reporting, as detailed in Figure 1.

Figure 1 Opex categories for SCS

RIN Category	Service Description	Forecast method
Vegetation management	• Planned programs and reactive maintenance activities in managing vegetation to provide a safe and reliable network.	Base-step-trend
Maintenance	• Inspection programs to detect potential defects requiring remedial response. • Maintenance plans to ensure delivery of supply, reliability, security and safety objectives.	Base-step-trend
Emergency response	• Works undertaken after a failure of an asset to either restore the network to a state in which it can perform its required function or render the installation safe. • Repair of damaged equipment and all storm-related repairs.	Base-step-trend
Non-network	• Expenditure relating to IT and communications assets, non-network buildings and property assets, fittings and fixtures, fleet, tools and equipment.	Base-step-trend
Network overheads	• Overhead costs including the provision of network, control and management services that cannot be directly identified with a specific operational activity (eg. network management, planning, network control and operational switching personnel, quality and standards functions, network billing, customer services, demand side management, levies etc.)	Base-step-trend
Corporate overheads	• Provision of corporate support and management services by the corporate office that cannot be directly identified with specific operational activity (eg. executive management, legal, HR, finance, debt raising etc)	Base-step-trend (except debt raising)

Ergon Energy will also present opex forecasts for Public Lighting and Metering, both of which are classed as Alternative Control Services (ACS).

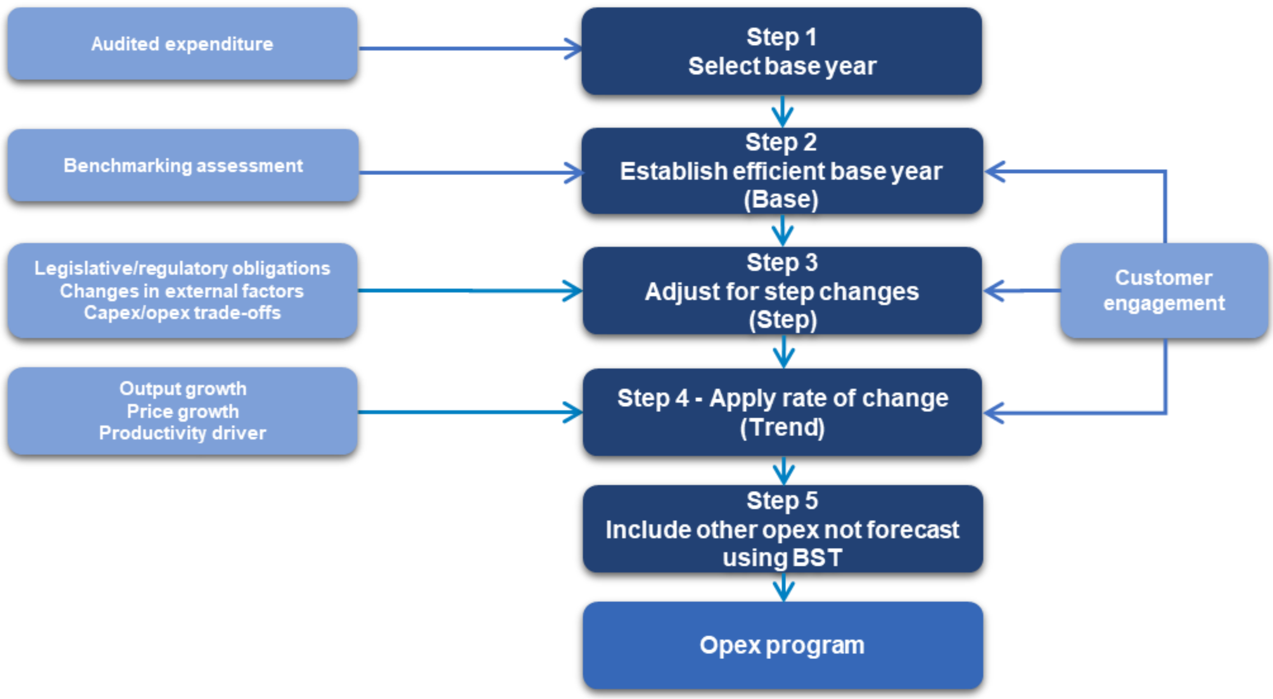
3.2 Overview of opex forecasting approach

The majority of our opex is forecast using the Base-Step-Trend (BST) method. This approach is described in the AER's Expenditure Forecasting Assessment Guideline and was used to set the opex allowance for the current regulatory period.

The remaining opex is forecast using a variety of methods including, benchmarking, market testing and bottom-up forecasts where appropriate.

The process for developing the opex forecasts is set out below and summarised in Figure 2.

Figure 2 Opex forecasting process



Step 1 – Select base year

The initial step in preparing a BST opex forecast is to select a base year that represents a realistic expectation of the efficient and sustainable on-going level of opex required to provide network services in the next regulatory period. The AER has indicated a preference for using the most recent year for which audited data is available.

The AER is expected to make its distribution determination for Ergon Energy in April 2025. Consequently, we consider that 2023-24 will be the most representative year to serve as a starting point for forecasting prudent and efficient opex.

Ergon Energy will be part-way through the 2023-24 financial year when the regulatory proposal is submitted to the AER in January 2024. Therefore, the regulatory proposal will use a partial forecast for the 2023-24 base year opex and will be updated with actual audited 2023-24 opex in our revised regulatory proposal.

This is consistent with the approach taken by the AER in recent determinations.

Step 2 – Establish efficient base year

Ergon Energy will adjust our 2023-24 base year opex as follows:

- add or subtract for changes in service classification or capitalisation policy;
- subtract specific one-off or unusual events, which are not representative of a typical year of recurrent opex in the next regulatory period;
- add any opex that is not appropriately accounted for in the base year but which will be incurred in the next regulatory period, and
- subtract opex that is not being forecast using the BST method – this is discussed in step 5 below.

Step 3 – Adjust for step changes

We may need to include step changes in our opex forecasts to account for events or obligations expected to occur in the next regulatory period and expected to either increase or decrease our opex relative to the base year.

Step changes can arise from:

- new regulatory or legislative obligations;
- changes in external factors outside of Ergon Energy's control and;
- capex/opex trade-offs, which move expenditure between capex and opex.

Step 4 – Adjust base opex for rate of change

The base year opex will reflect Ergon Energy's outputs, unit rates and productivity levels as at 2023-24. Therefore, the base year needs to be adjusted to reflect the expected outputs, prices and productivity in the next regulatory period. To do this, we expect to account for:

- output growth based on changes in customer volumes, circuit length and ratcheted maximum demand.
- real price growth based on expected real changes in labour and contractor prices.
- productivity growth having regard for customer engagement outcomes, benchmarking outcomes, management savings targets, and adjustments made for other DNSPs in recent regulatory determinations.

Step 5 – Include other opex not forecast using BST method

Ergon Energy intends to forecast the following components of our opex using alternative approaches to the BST method:

- Debt raising costs –Ergon Energy will adopt a debt raising cost unit rate, as measured in basis points, which will be multiplied by the assumed level of debt at the start of a year to determine the debt raising costs for that year. This unit rate may be based on advice from an independent expert, and/or having regard for the AER's recent regulatory determinations for other DNSPs.

4 CAPITAL EXPENDITURE

This section explains the methods that Ergon Energy proposes to use to forecast our prudent and efficient capex for SCS for the next regulatory control period. It:

- Explains the capex categories.
- Overviews our approach to capital investment selection.
- Summarises our capex forecasting methods.

4.1 Capex categories

Ergon Energy is required to present capex forecasts for SCS in seven categories for the purpose of the AER's Category Analysis RIN reporting, as described in Table 3.

Table 3: Capex categories

RIN Category	Expenditure Category Elements	Service Descriptions
Replacement expenditure (Repex)	Corporation initiated replacement & refurbishment of network assets. This includes replacing assets that have failed in service, have been identified as defective or are being proactively replaced to avoid the consequences of a future failure.	Maintaining the existing level of supply and standard of service by replacement or renewal of assets that are no longer capable of delivering their designed purpose.
Connections (Connex)	Customer initiated capital works to connect residential and small Commercial & Industrial customers to the network; upgrade existing connections; and provide service to connect small scale embedded generation.	Timely and cost-efficient connection of new customers to the distribution network and/or changes to existing small customer connections.
Augmentation expenditure (Augex)	Corporation initiated capital works to reinforce or grow the network to increase: • Capacity and Reliability • Power quality • Secondary systems • Clearance	Maintaining supply and standard of service by addressing fluctuations in peak demand, additional load, fault levels, adherence to structure or ground clearance standards, reliability and power quality requirements within the network, including the purchase of operational land and easements.
Distributed Energy Resources (DER) expenditure	Corporation initiated capital works to facilitate the integration of customer-owned DER.	Integrating DER into the network through Dynamic Connections and Operating Envelopes, DSO capability, assurance of the Basic Export Level, relief of curtailment of customer export where required and other network constraints arising from DER.
Non-network	ICT Fleet Buildings and property Other, such as tools and equipment	Other capex (not directly related to the construction or replacement of system assets) which supports the operation of the regulated network business.
Capitalised network overheads	Network overheads	Overhead costs include the provision of network, control and management services that cannot be directly identified with a specific activity
Capitalised corporate overheads	Corporate overheads	Provision of corporate support and management services by the corporate office that cannot be directly identified with specific activity.

Ergon Energy will also present our capex forecasts for Public Lighting and Metering (ACS).

4.2 Approach to capital investment

Our overall investment approach mirrors that of the AER's Expenditure Guideline. Each of the capital investments we seek to pursue in the 2025-30 regulatory period will be justified by one of the following.

Regulatory, Legislative or Legal Compliance

Where investment is required to achieve or maintain regulatory, legislative or legal compliance, we choose the lowest cost option of those available. We apply a high evidentiary burden to demonstrate legislative, legal or regulatory need. A negative cost/benefit outcome is acceptable where compliance is the main driver.

Examples of investments that fall into this category include:

- Distribution Authority compliance activities, such as meeting the Safety Net, Minimum Service Standards and Worst Performing Feeder program
- Meeting statutory requirements to meet minimum heights above the ground and structures on our overhead conductors (known as clearance projects)

Economic Value

For all other proposed capital investments, benefits will outweigh costs and we choose the highest value option of those identified. Timing will be optimized to ensure the most positive cost/benefit outcome based on a data-driven, monetized risk-based assessment. A positive cost/benefit is essential in these cases.

Five value streams are considered for cost/benefit analysis for each identified option of each proposed investment. The five value streams are summarised in Figure 3.

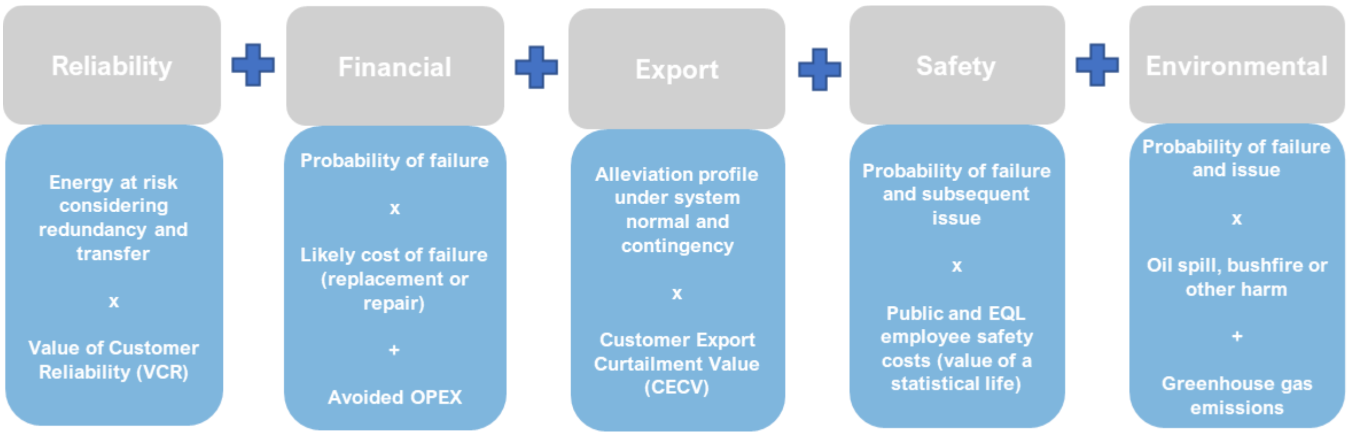


Figure 3 – Value Streams for Investment Justification

4.3 Capex forecasting methods

Ergon Energy uses three broad methods to forecast capex in the seven categories detailed in section 4.1:

- Scoped capex – this bottom-up method involves scoping and costing individual projects;
- Program capex – this bottom-up method involves forecasting volumes of work and unit costs for programs of work for different asset classes. This includes forecasts for both replacements following asset failures and defects;
- Pooled capex – this top-down method involves forecasting categories of capex at an aggregate level, such as based on a prior year's expenditure or historical trends; and

Table 4 summarises the forecasting methods that Ergon Energy proposes to use for each capex category.

Table 4: Capex forecasting methods

Expenditure Type	Scoped	Program	Pooled
Repex	✓	✓	
Augex	✓	✓	
Connex		✓	✓
DER	✓	✓	
Non-network	✓	✓	✓
Network Overheads		✓	✓
Corporate Overheads		✓	✓

Appendix A. Definitions, acronyms, and abbreviations

Term	Definition
ACS	Alternative Control Services, the services that are provided in response to a customer request. The cost of these services is recovered through specific charges to the individual customers who require the service.
AER	Australian Energy Regulator
Augex	Augmentation capex
BST	Base-step-trend, the AER’s preferred forecasting method for total opex forecasts.
Capex	Capital expenditure
Connex	Connections capex
DER	Distributed energy resources e.g. customer-owned wind/solar generation
DNSP	Distribution Network Service Provider
Energy Queensland	Energy Queensland Limited, the legal entity for the Energy Queensland Group, which is the parent company of both Energex and Ergon Energy
Expenditure Forecasting Assessment Guideline	The AER’s guideline that describes how it will assess distribution network service providers’ expenditure forecasts
NER	National Electricity Rules
Non-network ICT	Technology that is not directly related to the control and operation of the network. This comprises ICT assets that are not integrated or embedded in the primary network assets such as substations and lines.
Opex	Operating expenditure
PoW	Program of work
Repex	Replacement capex
RIN	Regulatory Information Notice
SCS	Standard control services, the common distribution services provided using the shared Energex and Ergon Energy Network networks. The costs of these services are recovered through network tariffs.