Powerlink 2027-32 Revenue Proposal

January 2026

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Executive summary

This Revenue Proposal outlines the Queensland Electricity Transmission Corporation Limited's (Powerlink's) revenue requirements for prescribed (regulated) transmission services for the five-year regulatory period from 1 July 2027 to 30 June 2032.

Powerlink is a Government Owned Corporation that owns, develops, operates and maintains the high voltage electricity transmission network in Queensland. Our network extends 1,700km from Cairns to the New South Wales (NSW) border.

We lodge our Revenue Proposal with the Australian Energy Regulator (AER) every five years as part of our revenue determination process. We see this process as a once-in-a-five-year opportunity to continue to build trust with our customers and other important stakeholders, including the AER. It is important as it sets about 70% of our total annual revenue and funds the capital and operating expenditure required to provide safe, reliable and cost-effective prescribed (regulated) transmission services.

The challenge

Our network serves more than five million Queenslanders, for which the cost of electricity remains a key issue. It has never been more important or challenging for a network business to get the balance right between appropriate investment to ensure reliable supply, and minimising price impacts to customers.

Our research shows that our customers view affordability and reliability as the most important factors to consider in future network investment, and that they support investment now for long-term benefits in the future.

Appropriate investment in the transmission network is needed to meet our regulatory obligations and enable a strong Queensland economy. We recognise our impact on customer affordability is not limited to the prices we charge for transmission services. Our role in connecting generation and storage is essential in ensuring customers have access to the lowest cost electricity when they need it.

Powerlink's network is becoming increasingly complex to manage. The widening gap between maximum and minimum demand, increasing cyber security risks, new regulatory obligations (including system strength responsibilities), and an ageing asset base all drive additional cost and operating challenges. Making the right investment at the right time is essential to maintain a safe and reliable electricity supply without placing unnecessary burden on Queensland households already facing cost of living pressures.

Overview of our Revenue Proposal

We have engaged extensively with our customers and other stakeholders, including the AER's Consumer Challenge Panel on all key elements of our Revenue Proposal. We have listened and acted on customer feedback, particularly around our approach and how we manage the increasing complexity of the energy system.

Key elements of our Revenue Proposal are as follows.

TRANSMISSION COMPONENT OF ELECTRICITY BILLS WILL INCREASE ANNUALLY	FORECAST CAPITAL EXPENDITURE	FORECAST OPERATING EXPENDITURE	MAXIMUM ALLOWED REVENUE
5%	**$2,499.5 million**	**$1,810.2 million***	**$5,265.3 million***
For average residential and small business customers, this is an indicative first-year increase of $7 and $14 respectively.	This is a 66% increase from the actual/forecast capital expenditure in the current regulatory period.	This is a 19% increase from the actual/forecast operating expenditure in the current regulatory period. ** excl. debt raising costs*	This is a 25% increase from the current regulatory period. ** unsmoothed*

An increasingly complex and dynamic operating environment

Our operating environment is markedly different now to when we lodged our previous Revenue Proposal in January 2021. Our priority remains to deliver safe, reliable and cost-effective transmission services to our customers. We have summarised the key factors that shape our operating environment into three themes.

Customers

Powerlink's operating environment is increasingly shaped by the priorities of our customers and other stakeholders who expect our services to be reliable and affordable. We recognise our impact on affordability is influenced not only by our transmission service prices but also by network outages and congestion, which can lead to higher wholesale prices. We continue to guide the market to minimise bulk electricity supply costs.

In developing our plan of future network investment needs, we considered the Queensland Government's Energy Roadmap 2025 and Australian Energy Market Operator's (AEMO's) Integrated System Plan (ISP), which provide infrastructure development pathways that are intended to provide customers with the lowest overall cost of electricity supply over time.

Cost

Powerlink, like other network businesses across the National Electricity Market (NEM) and globally, is experiencing significant increases in equipment costs, supply chain pressures and competition for skilled resources. AEMO's 2025 Electricity Network Options Report identified that the costs for transmission line projects in Australia have increased by up to 55% in real terms since 2023, citing supply chain pressures, market competition and increased project risk associated with remote locations and community impacts.

Complexity

The rapid shift towards distributed generation and rooftop solar presents technical challenges in how we plan and operate our network. It drives more frequent operator intervention, an increasing number of control room alarms, and a rise in the labour effort required for scheduling, planning and management of outages. At the same time, heightened cyber security risk and the importance of social licence continue to shape how we do business.

Genuine customer engagement has shaped our Revenue Proposal

Our purpose is firmly focused on serving Queenslanders. Powerlink engages with its customers, communities and other stakeholders in the normal course of business. This includes with our customers via our Customer Panel, Transmission Network Forums and targeted research and engagement with broader stakeholders including government, households and communities. We co-designed the scope of engagement for our Revenue Proposal with Powerlink's Customer Panel, senior members of the AER, the AER's Consumer Challenge Panel, as well as members of Powerlink's Board and Executive.

Our Revenue Proposal Reference Group (RPRG), a subset of our Customer Panel, met 11 times throughout 2025 to engage on key elements of this Revenue Proposal. We also expanded the scope of our annual customer and stakeholder research programs to gain greater insight into customer priorities.

The direct influence of the RPRG has shaped the development of our Revenue Proposal, including:

- smoothing the price path
- Capital Expenditure Sharing Scheme (CESS) net carryover calculation
- operating expenditure output growth trend, and
- application of the Demand Management Innovation Allowance Mechanism (DMIAM).

A key finding from our engagement assessment survey of the Customer Panel, was that 100% of RPRG members considered that our engagement process had allowed appropriate influence on decision making and that they had been engaged at an appropriate level.

Capable of acceptance remains our overarching goal

Through engagement with our customers and other stakeholders, we have retained our overarching goal:

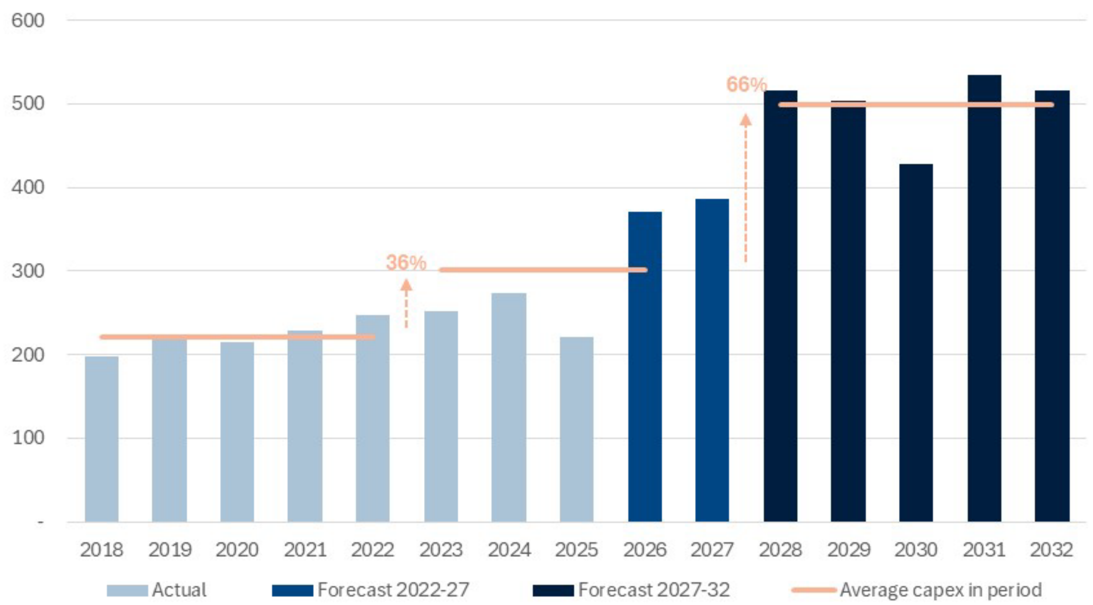
To deliver a Revenue Proposal that is capable of acceptance by our customers, the AER and Powerlink.

This goal has influenced the development of our Revenue Proposal and encapsulates the key customer priorities of affordability and reliability. We have also engaged extensively with the RPRG to define what capable of acceptance looks like and developed clear criteria based on the principles contained in the AER's Better Resets Handbook.

Capital expenditure aligned with customer priorities

Our total capital expenditure forecast for the 2027-32 regulatory period is $2,499.5 million**.** This is $995.0 million (66%) more than the capital expenditure for the current 2022-27 regulatory period.

Figure 1 - Total actual historical and forecast capital expenditure ($million, real 2026/27)



The majority of our forecast capital expenditure (78%) is network capital expenditure to maintain safe and reliable supply. This includes $1,674 million reinvestment on our ageing assets, and $167 million to address obligations under the *Security of Critical Infrastructure (SOCI) Act 2018*. A further $98 million is planned to be invested to enhance monitoring and real time operational capability. These forecasts are based on a bottom-up assessment of needs, balancing risks to safety, security and reliability and cost, consistent with the priorities expressed in our customer surveys.

Our capital expenditure forecast also includes $295 million to acquire easements to support future transmission line rebuilds in the North Queensland and Gladstone regions, further enabling the ongoing energy transition. We also propose a major investment in our Virginia complex, where the underlying infrastructure is over 60 years old, and the establishment of a permanent facility in Gladstone.

Our capital expenditure forecast is supported by an assessment of its deliverability.

Current period performance in a challenging environment

During the 2022-27 regulatory period, Powerlink experienced unprecedented increases in the costs of major plant items, materials and skilled resources which were outside our control. We have managed our expenditure and proactively sought to address these inflationary pressures where practical, and deferred work where it has been safe and efficient to do so. This has included application of the outcomes of our Asset Reinvestment Review to transmission line refit works and measures to reduce secondary systems replacement needs.

Notwithstanding the actions taken to reduce capital expenditure, we spent an additional $63.4 million (6.3%) in the ex post capital expenditure review period, the preceding five complete years of actual expenditure, compared to the AER's allowance as shown in Table 1. We do not consider this overspend is material, based on the circumstances we have faced during this time.

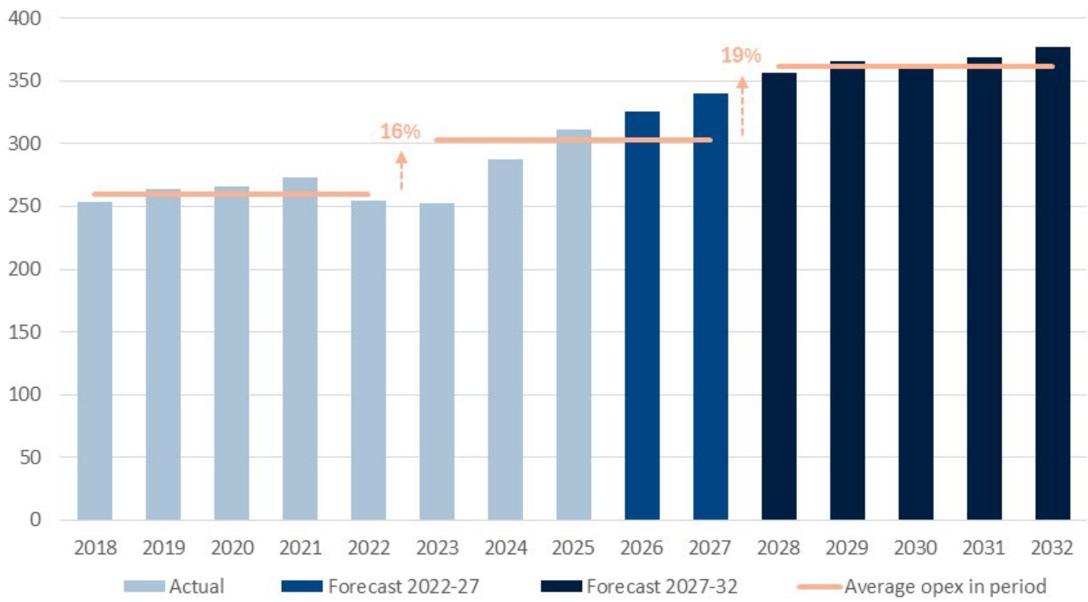
Table 1 - Capital expenditure – ex post review period ($million, nominal)

	2021	2022	2023	2024	2025	Total
AER Allowance	185.5	179.7	209.3	239.9	184.9	**999.4**
Actual	180.5	201.7	221.8	250.6	208.2	**1,062.8**
Difference	(5.1)	22.0	12.5	10.7	23.2	**63.4**
Difference (%)	(3%)	12%	6%	4%	13%	**6.3%**

Operating expenditure to address the demands of a complex operating environment

Our total operating expenditure forecast for the 2027-32 regulatory period is $1,810.2 million, excluding debt raising costs**.** This is $293.0 million (19%) more than the operating expenditure for the current 2022-27 regulatory period.

Figure 2 - Total actual historical and forecast operating expenditure ($million, real 2026/27)



We developed our forecast using the AER's preferred base-trend-step methodology. We propose 2025/26 as our base year, as we consider it is reflective of an efficient level of the expenditure required to meet the operating expenditure objectives and criteria. It will also represent the most recent revealed costs at the time that the AER makes its Final Decision on our 2027-32 Revenue Proposal in April 2027.

We explored alternative output growth measures that better reflect our rapidly changing operating environment. However, following engagement with the RPRG, we have applied trend measures for output growth, price growth and productivity in line with the AER's current approach.

We have also proposed three operating expenditure step changes, totalling $85 million for the 2027-32 regulatory period. These result from new regulatory obligations and external market conditions relating to physical security, cloud-based computing solutions and enhancing overnight network monitoring in our control room.

Revenue and pricing

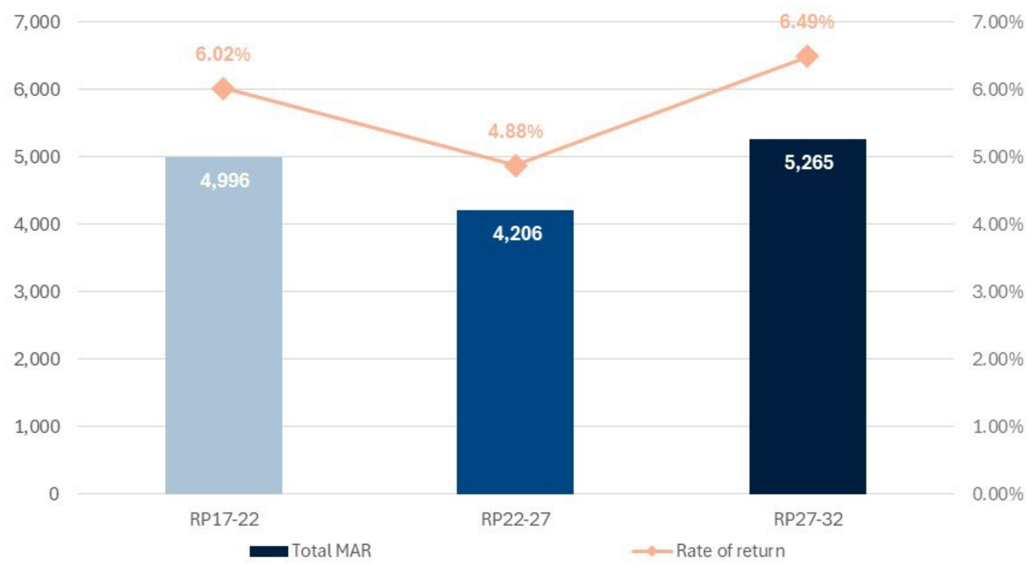
Revenue requirements

Our Maximum Allowed Revenue (MAR) forecast for the 2027-32 regulatory period is $5,702.0 million ($ nominal) or $5,265.3 million ($ real, 2026/27). This is $1,059.0 million (25%) higher than our allowed MAR in real terms for the current 2022-27 regulatory period.

The increase in revenue is mainly driven by significantly higher rates of return, growth in the Regulatory Asset Base (RAB) due to increased capital expenditure, and higher operating expenditure reflecting changes in the operating environment.

The average MAR over the previous, current and next regulatory periods and its alignment with the prevailing average rate of return is illustrated in Figure 3.

Figure 3 - Maximum Allowed Revenue ($million, real 2026/27) and average rate of return (%)



We actively engaged with the RPRG to ensure our approach to revenue smoothing was transparent and genuinely reflected customer interests. Together, we explored different options and the RPRG supported a method that balances revenue recovery with expected demand growth, providing a smoother price path for customers over the 2027-32 regulatory period. Powerlink has adopted this approach in calculating the smoothed revenue and resulting X-factors which are shown in Table 2.

Table 2 - X-factors and smoothed MAR ($million nominal)

	2028	2029	2030	2031	2032	Total
Unsmoothed revenue requirement	1,025.0	1,043.8	1,111.6	1,208.6	1,313.0	**5,702.0**
X-factors	(2.54%)	(3.00%)	(4.25%)	(5.94%)	(7.38%)	
Smoothed MAR	**989.8**	**1,046.0**	**1,118.8**	**1,216.0**	**1,339.7**	**5,710.2**

Indicative price path

Based on our forecast smoothed revenue, the indicative impact on the transmission component of electricity bills in the first year of the next regulatory period (2027/28) would be:

- **Residential –** a nominal increase of $7 (5%)
- **Small business –** a nominal increase of $14 (5%)

The annual price increases for average residential customers and small businesses will be 5% in nominal terms for the remainder of the 2027-32 regulatory period. Our price path reflects customers' preference for a stable and predictable price path, consistent with feedback from the RPRG.

The indicative impact of our forecast MAR on the transmission component of average annual electricity bills in each year of the 2027-32 regulatory period is shown in Table 3.

Table 3 - Indicative impact on transmission component of average annual electricity bills ($ nominal)

	2027	2028	2029	2030	2031	2032
Residential annual bill	148	155	163	171	179	188
Annual change		7	8	8	8	9
Small business	288	302	317	332	349	366
Annual change		14	15	15	16	17

We also considered the potential price impacts of projects subject to regulatory mechanisms outside the revenue determination process, including the Gladstone Project. More information on this is provided in Appendix 10.01 Pricing Impact Scenarios of our Revenue Proposal.

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1 Introduction

This Revenue Proposal presents Queensland Electricity Transmission Corporation Limited's (Powerlink's) proposed revenue requirements for prescribed (regulated) transmission services for the five-year regulatory period from 1 July 2027 to 30 June 2032.

We have developed our Revenue Proposal consistent with Chapter 6A of the National Electricity Rules (Rules), the Australian Energy Regulator's (AER's) Framework and Approach Paper[1] and the Regulatory Information Notice (RIN) issued to Powerlink by the AER for the purpose of this Revenue Proposal (the Reset RIN)[2].

Our Revenue Proposal provides an overview of our operating environment, customer engagement process, expenditure forecasts and proposed revenue requirements for the 2027-32 regulatory period. Our Revenue Proposal reflects the outcomes of extensive engagement with our customers and other stakeholders, including our Customer Panel and a sub-group of that panel, the Revenue Proposal Reference Group (RPRG). We acknowledge their time and resource commitment as part of this process, which has provided us with valuable insights and feedback on key aspects of our Revenue Proposal.

Our Revenue Proposal comprises:

- an overview paper presenting a 'plain language' summary of our Revenue Proposal
- the Revenue Proposal (this document)
- appendices and supporting information for the Revenue Proposal
- models, templates and supporting information required by the Rules and the Reset RIN, and
- our Proposed Pricing Methodology.

1.1 About Powerlink

We are a Government Owned Corporation that owns, develops, operates and maintains the electricity transmission network in Queensland. Our transmission network runs approximately 1,700km from Cairns to the New South Wales (NSW) border.

Our role in the electricity supply chain is to transport high voltage electricity from large generators through the transmission network to the distribution networks owned by Energex and Ergon Energy (part of the Energy Queensland Group) and Essential Energy (in northern NSW) and to ensure a safe, reliable and cost-effective power supply to more than five million Queenslanders. We also transport electricity to industrial customers such as rail companies, mines and mineral processing facilities, and to NSW via the Queensland/NSW Interconnector (QNI) transmission line.

We are registered with the Australian Energy Market Operator (AEMO) as a Transmission Network Service Provider (TNSP) and are the System Strength Service Provider and Inertia Service Provider for Queensland. We hold a Transmission Authority issued under the *Electricity Act 1994 (Qld)* and have been appointed by the Queensland Government as the entity responsible for transmission network planning in Queensland (the Jurisdictional Planning Body) for the purpose of the Rules[3].

[1] Framework and Approach Paper Powerlink transmission determination 2027-32, Australian Energy Regulator, July 2025.
[2] 2027-32 Reset RIN for Powerlink, Australian Energy Regulator, 9 October 2025 (as varied 28 November 2025).
[3] Specific duties of the jurisdictional planning body are detailed in Chapter 3 Market Rules and Chapter 5 Network Connection Access, Planning and Expansion of the National Electricity Rules.

1.2 Our services

We provide prescribed transmission services consistent with the Rules, the *Electricity Act 1994 (Qld)*, the *Energy (Infrastructure Facilitation) Act 2024* and our Transmission Authority. These services include:

- shared transmission services provided to directly connected customers and distribution networks (prescribed Transmission Use of System services)
- connection services for the Distribution Network Service Providers (DNSPs) who are connected to our transmission network (prescribed exit services)
- grandfathered connection services provided to generators and customers directly connected to the transmission network that were in place on 9 February 2006 (prescribed entry and exit services), and
- services required under the Rules or to comply with jurisdictional electricity legislation that are necessary to ensure the integrity of the transmission network, including through the maintenance of power system security and quality (prescribed common transmission services).

The quality, reliability and security of supply of the prescribed transmission services we provide are established in the Rules, our Transmission Authority (and other jurisdictional legislation and instruments), and customer connection and access agreements.

1.3 Structure of our Revenue Proposal

We have provided an overview of the remaining chapters of this Revenue Proposal in Table 1.1. In line with the RPRG's preference, we have combined historical and forecast expenditure within a single chapter each for capital and operating expenditure.

Table 1.1 – Structure of our Revenue Proposal

Chapter	Description
2	Our **operating environment** and the opportunities and challenges this presents in the 2027-32 regulatory period
3	How we undertook **customer engagement** and how this has influenced our Revenue Proposal
4	Overview of historical and forecast **capital expenditure** for the 2027-32 regulatory period
5	Overview of historical and forecast **operating expenditure** for the 2027-32 regulatory period
6	The cost **escalation rates** used in our forecasts
7	Calculation of our **Regulatory Asset Base** (RAB), including our proposed additions and removals
8	Forecasts of **rate of return, taxation and inflation** included in our forecasts
9	Our regulatory **depreciation** forecast
10	Forecast of the **Maximum Allowed Revenue and price impact** for the 2027-32 regulatory period
11	Our proposed **pass through events**
12	Assessment of **shared assets** unregulated revenues
13	Overview of **incentive schemes** including outcomes from this regulatory period and targets and inclusions for the 2027-32 regulatory period
14	Our proposed **pricing methodology**

1.4 Conventions

Our Revenue Proposal applies the following numbering conventions, unless otherwise specified.

- Regulatory periods are expressed consistent with the AER's convention, e.g. 2027-32 refers to the regulatory period 1 July 2027 to 30 June 2032.
- Where our Revenue Proposal for the current 2022-27 regulatory period is referenced, it uses the published name of our 2023-27 Revenue Proposal.
- Years referenced in tables and figures relate to financial years (July – June) unless otherwise stated.
- Negative values in tables are presented in brackets.
- All capital expenditure values in tables are net of disposals, unless otherwise stated.
- Actual and forecast capital expenditure values reported do not include any margins paid or expected to be paid to related parties.
- Actual and forecast capital expenditure is presented in end-year (to 30 June) real 2026/27 dollars.
- Actual and forecast operating expenditure is presented in end-year (to 30 June) real 2026/27 dollars.
- Our revenue building blocks from the Post-tax Revenue Model (PTRM) are presented in end-year nominal dollars.

Totals presented in tables may not add up due to rounding.

The source of all figures and tables is Powerlink, unless otherwise specified.

1.5 Confidential information

We do not claim confidentiality over any part of this Revenue Proposal document. However, some components of the Revenue Proposal, including supporting documents, are confidential and we have clearly noted these in the Confidentiality Register provided with our Revenue Proposal.

Where confidential information has been identified in separate appendices and supporting information, a confidential version has been provided to the AER and registered consistent with the AER's Confidentiality Guideline[4].

1.6 Governance and compliance

Our Board has certified that the key assumptions that underlie the capital and operating expenditure forecasts in this Revenue Proposal are reasonable[5] (refer Appendix 1.01), with these key assumptions included in Attachment 1 of this Revenue Proposal.

We also provide a Statutory Declaration from our Chief Executive in relation to the historical and forecast data contained in our Reset RIN (refer Appendix 1.02).

To assist the AER in assessing our Revenue Proposal's compliance with the Rules, we have provided a compliance checklist in Appendix 1.03. Our compliance checklist to the Reset RIN is provided in Appendix 1.04.

We have provided a document register, consistent with the requirements of Section 4.2.1 of the Reset RIN, in Appendix 1.05.

[4] Better Regulation: Confidentiality Guideline, Australian Energy Regulator, August 2017.
[5] National Electricity Rules, clauses S6A.1.1(5) and S6A.1.2(6).

2 Operating Environment

2.1 Introduction

This chapter sets out the key external drivers that impact Powerlink or are expected to impact Powerlink over the 2027-32 regulatory period and beyond.

This chapter builds on the business narrative developed with the Revenue Proposal Reference Group (RPRG) early in our customer engagement process for this Revenue Proposal (refer Chapter 3 Customer Engagement and Appendix 2.01 Business Narrative).

Key highlights:

- Our operating environment has changed significantly since we lodged our 2023-27 Revenue Proposal in January 2021. Unprecedented rises in transmission equipment prices and supply chain shocks have seen costs rising at multiples of the prevailing inflation rates. Compounding matters, the power system is becoming more complex to operate due to the changing nature of generation and demand.
- We consider that our forecast expenditure for the 2027-32 regulatory period is prudent, efficient and essential to the delivery of safe, reliable and cost-effective electricity supply.
- We have grouped the key elements of our operating environment in the 2027-32 regulatory period into themes of customers, costs and complexity.

  Customers
    - Affordability remains a key concern for customers, alongside predictable prices and a reliable, resilient electricity supply. These priorities continue to shape Powerlink's focus and decision making.

  Costs
    - A combination of global and local factors is placing significant pressure on delivery costs, and we expect this to continue into the 2027-32 regulatory period.
    - We have experienced unprecedented increases in the cost of major plant items since 2021; future cost increases are expected to revert to historical growth rates in line with inflation over the 2027-32 regulatory period.
    - We have sought proactive solutions to rising costs, such as developing new supply arrangements for key equipment and enhancing targeted investment on existing transmission lines.

  Complexity
    - System complexity encompasses changes in network demand and connectivity to the network, including increased cyber threats to the digital and telecommunications networks necessary to operate the transmission network.
    - Deliverability includes factors that can have a material impact on the cost and timeframe of projects, such as social licence to operate, workforce capacity and capability, and State and Federal Government approval processes.
    - Our approach now embeds social performance within our core processes, aligning with government policy, regulatory frameworks, and the Energy Charter's Better Practice Social Licence Guideline.

2.2 Our approach

Our operating environment continues to present challenges and risks, but also opportunities for Powerlink. Our priority remains to deliver safe, reliable and cost-effective prescribed transmission services to our customers. We also continue to have an ongoing role in guiding the market in Queensland, including through our Transmission Annual Planning Report, during a period of significant change for the energy industry and our customers.

We have summarised the key elements within our operating environment into three themes: customers, costs and complexity. These themes influence and impact our day-to-day business and how we plan the future development and operation of our network. Consequently, they underpin various components of our Revenue Proposal and are discussed in further detail in this chapter.

2.3 Customers

Our purpose is to connect Queenslanders to a world-class energy future. We aim to achieve this by consistently prioritising their long-term interests throughout the energy transition. Our purpose is supported by four strategic objectives, including to *Drive value for Queenslanders.*

We put customers at the centre of our decision making and maintain a sharp focus on the cost-effective delivery of our services. We are proud to be a foundation signatory to The Energy Charter and remain committed to its principles[6]. We recognise that to deliver against these principles we must continue to seek customer views and input to inform our Revenue Proposal, as well as our day-to-day business activities.

The following sections outline the key elements that have shaped our Revenue Proposal, reflecting what customers told us matters most: affordability, price predictability, and a reliable and resilient electricity supply.

More detail on our engagement approach and response to customer feedback on our Revenue Proposal is provided in Chapter 3 Customer Engagement.

2.3.1 Affordability

Our network serves more than five million Queenslanders, for whom the cost of electricity remains a key concern.

The 2025 Queensland Household Energy Survey[7] highlighted significant ongoing concerns about electricity affordability, particularly among renters (66%), households without rooftop solar (58%), and those with lower incomes[8] (56%). In addition, AER research showed that more than 60,000 residential customers in Queensland were on either a payment plan or a hardship program to manage their electricity payments[9]. In particular, the number of customers on a hardship program has increased since 2020/21 by more than 13,000 (74%) to 30,759.

Our transmission network charges comprise around 7% of the average residential household bill in Queensland (refer Figure 2.1). With this front of mind, we will continue to guide the market to minimise bulk electricity supply costs for our customers.

[6] The Energy Charter established five principles, including *We will put customers and communities at the centre of our business and the energy system,* and *We will improve energy affordability and value for customers and communities* (refer https://www.theenergycharter.com.au/about/)
[7] Queensland Household Energy Survey (qhes.com.au).
[8] Less than $31,000 per annum.
[9] Annual retail markets report 2024-25 - Jurisdictional snapshot, Australian Energy Regulator, November 2025.

Figure 2.1 - Breakdown of typical Queensland household electricity bill

7%

The cost of Powerlink's high voltage electricity grid represents around 7%* of the total delivered cost of electricity for the typical Queensland residential electricity consumer.

Electricity supply chain components	Proportion of electricity bill
Generation	39%
Transmission	7%
Distribution	30%
Retail	21%
Environmental policies	3%

* Calculations based on the Australian Energy Regulator's 2025-26 Default Market Offer Prices publication and Energex's 2025-26 Pricing Proposal Overview.

Powerlink's 2023-27 Revenue Proposal, lodged with the AER in January 2021, sought to respond to affordability concerns by forecasting a small decrease in our capital expenditure and no real growth in operating expenditure compared to the 2018-22 regulatory period. While these targets were set in the context of Powerlink's reasonable expectations of the operating environment at that time, the circumstances that unfolded are very different. In particular, unprecedented increases in transmission equipment prices driven by increased global demand, and the increasing complexity of the operating environment meant that we were unable to deliver our capital and operating expenditure programs as originally planned.

We continued to target improved outcomes for our customers in our capital expenditure planning, engaging with customers and other stakeholders, including the AER, as part of our Asset Reinvestment Review[10] which commenced in 2022. The review considered alternative strategies for transmission line refit works and resulted in the deferral of capital works within the current 2022-27 regulatory period.

We commenced a trial of in-situ replacement of secondary systems panels. The trial is expected to reduce costs, support shorter network outage times and enhance our capability. Powerlink will continue to develop this and other innovative approaches to addressing network needs in the context of a changing environment.

Our capital expenditure forecasts build on these reviews and incorporate efficiencies in line with the expected benefits. This is discussed further in Chapter 4 Capital Expenditure.

We also continue to seek innovative ways to prioritise work and enhance utilisation of resources to manage the cost impacts on operating expenditure. These improvements have been factored into our forecasts, which we discuss further in Chapter 5 Operating Expenditure.

We recognise our impact on affordability is not limited to the prices we charge for prescribed transmission services. Our role in connecting new generators and storage facilities, such as pumped hydro energy storage (PHES) and battery energy storage systems (BESS), across Queensland is important to ensure customers have access to the lowest cost electricity when they need it.

[10] Asset Reinvestment Review, Powerlink, June 2023.

Network outages, constraints and congestion on the transmission network can lead to higher wholesale prices, if lower cost generation is constrained and more expensive generation is required to meet customer demand. As part of the economic assessment for major new transmission network investments, we analyse the potential benefits of improved network operation on the wholesale market. In this way we seek the best overall outcome for our customers.

In developing our plan of future network investment needs, we have aligned with the Queensland Government's Energy Roadmap 2025[11] which charts a pragmatic path to meet the State's energy needs over the next five years and beyond. Our capital expenditure forecast, and proposed contingent projects, enable the transmission network to keep pace with demand growth and decentralisation as new generation and storage capacity connects to the grid. We also have regard to the Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP), which presents a coordinated approach to necessary transmission developments in the National Electricity Market (NEM) and a plan for Australia's eastern power system for the next 20 years.

We are committed to delivering cost-effective transmission services to improve affordability within an increasingly complex operating environment. Consistent with that commitment, we have worked to ensure that our forecast expenditure for the 2027-32 regulatory period is prudent, efficient and essential to the delivery of safe, reliable and cost-effective electricity supply.

2.3.2 Price predictability

Large commercial and industrial (C&I) customers in Queensland, including our directly connected customers, value stable prices and predictability in future charges. This was clearly identified in a recently conducted survey with large C&I customers of both Energy Queensland and Powerlink. For this reason, we engaged with the RPRG and major customers to develop our position on an appropriate approach to smoothing the indicative price path in our Revenue Proposal. As a result, we applied a balanced approach to smooth revenues to deliver a more stable price path over the 2027-32 regulatory period. We discuss this approach further in Chapter 10 Maximum Allowed Revenue and Price Impact.

For the purposes of this Revenue Proposal, we have proposed largely administrative changes to our Pricing Methodology to reflect recent Rule changes. We discuss the customer surveys and related engagement in Chapter 3 Customer Engagement, while Chapter 14 Pricing Methodology discusses the proposed pricing methodology changes in further detail.

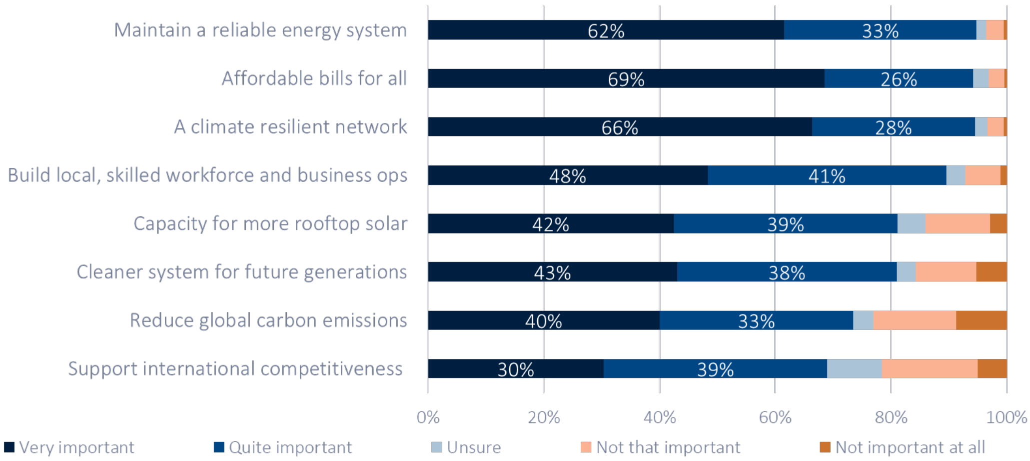
2.3.3 Reliability and resilience

Reliability of supply, even during extreme weather events, is important to our customers.

The results of the 2025 Queensland Household Energy Survey indicate that households considered investment to support reliability and resilience of the network as important (very important or quite important), as illustrated in Figure 2.2. Three-quarters of households that responded considered that they had a reliable electricity supply, with only 3% unhappy with the reliability of their supply.

[11] Queensland Energy Roadmap 2025, Queensland Treasury, October 2025.

Figure 2.2 - Importance of investment by purpose (Source: Powerlink, QHES)



Our large C&I customers rated the need for reliability as a high priority, and it was also a concern for the agricultural sector. Extreme weather events and supply disruptions disproportionately affect rural areas, where the remote location of assets and the absence of diverse supply paths can result in longer restoration times and more frequent outages.

Electricity is an essential service, yet those most affected by higher prices often have fewer options to reduce demand. As rooftop solar and household battery adoption continues to grow, support will be necessary to address cost impacts on vulnerable and lower income groups who may be unable to access these consumer energy resources.

We are committed to addressing these challenges by advancing a low-cost energy transition, ensuring fair cost allocation, aligned with the principles of distributional and procedural fairness, and building partnerships across the energy supply chain to achieve better outcomes for customers.

Our capital expenditure forecast has been prepared to ensure the ongoing reliability and resilience of our network and is presented in Chapter 4 Capital Expenditure.

2.4 Costs

At the time of lodging our 2023-27 Revenue Proposal with the AER in January 2021, Powerlink's operating environment was markedly different to today. Our forecasts of a reduction in capital expenditure and no real growth in operating expenditure were reasonable at the time and reflective of our view of the future operating environment. It was aimed at keeping costs low for Queenslanders, while continuing to provide prudent and efficient transmission services.

Events such as the long-tailed global supply disruption following COVID-19, Russia's invasion and war in Ukraine, and global targets for emissions reduction driving unprecedented demand for materials, equipment and specialised labour could not have been reasonably foreseen at that time.

These cost pressures are not unique to Powerlink, with similar trends being experienced by other transmission and distribution businesses across the NEM, and indeed, around the globe. We expect the global and local competition impacting the supply chain to continue for the foreseeable future, with a challenging operating environment continuing throughout the 2027-32 regulatory period.

2.4.1 Global impacts

The ongoing increased demand for materials, equipment and specialised labour is driven primarily by global structural shocks to historical trade patterns for energy due to the Russia-Ukraine war and commitments to net-zero greenhouse gas emissions targets. The latter continues to drive a significant shift in the mix of generation globally, and the need to substantially expand electricity networks to accommodate the shift.

Over 100 countries have adopted net-zero pledges by the middle of the century, representing about 70% of current global greenhouse gas emissions[12]. To support these targets, the global demand for new electricity infrastructure is substantial. In November 2025, the International Energy Agency (IEA) identified that under current policy settings for emissions reductions, 25 million kilometres of new transmission and distribution lines would need to be delivered by 2035 and a further 20 million kilometres of existing lines would need to be replaced[13]. This is equivalent to over half of the existing global grid in the next decade.

The Energy Transitions Commission, a global coalition of leaders from energy producers, energy users, financiers and environmental groups, identified a similar need, stating in September 2024 that global networks must grow from around 68 million kilometres to a range of around 110–200 million kilometres by 2050[14]. The investment required for this necessary expansion is estimated to reach US$650 billion per year by 2035[15], a 67% increase on current global investment levels.

Locally, Infrastructure Australia published its Infrastructure Market Capacity Report in November 2025. The forecast expenditure for the five-year outlook, from 2025 to 2029, for utilities infrastructure investment is $36 billion[16]. This is predominantly due to transmission line projects and represents a $20 billion increase on the previous year's outlook.

The impact of this significant global and local demand on the cost of transmission projects in Australia has been reflected in the 2025 Electricity Network Options Report published by AEMO. In its update to the ISP Transmission Cost Database, GHD Advisory noted that global demand along with Australian demand is competing for the same pool of skills, production floor capacity and other supply chain arrangements[17]. As a result of these global and local cost pressures, the 2025 Electricity Network Options Report identifies that the costs for transmission line projects have increased by up to 55%, while transmission substation projects have increased by up to 35%, in real terms since 2023[18].

AEMO notes that the cost increases are primarily driven by:

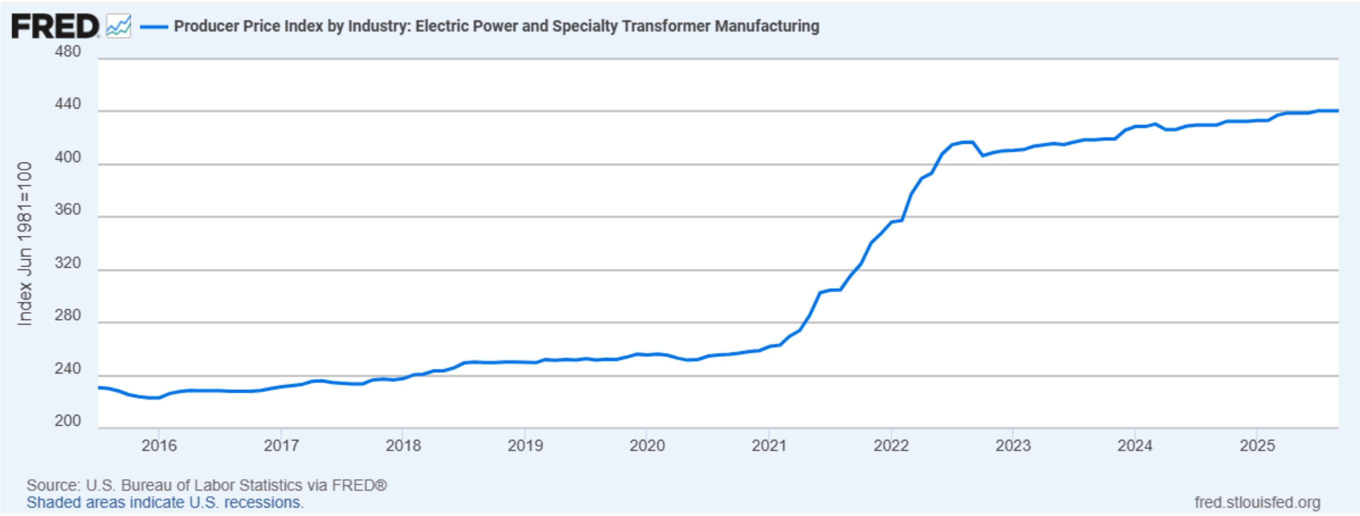
- sustained supply chain pressures on materials, equipment and workforce
- market competition driven by a high number of concurrent projects under development in the NEM
- project complexity, including an increased number of projects planned for remote areas
- social licence to operate imperatives, including regular community and landholder engagement along proposed transmission line routes, and
- additional contracting costs to account for risk allocation in engineering, procurement and construction contracts in response to pressures in the current market.

[12] Emissions Gap Report 2025, United Nations Environment Programme, November 2025, page xii.
[13] World Energy Outlook 2025, International Energy Agency, November 2025, pages 148-149.
[14] Building grids faster: the backbone of the energy transition, Energy Transitions Commission, September 2024, page 9.
[15] World Energy Outlook 2025, International Energy Agency, November 2025, page 150.
[16] Infrastructure Market Capacity 2025 Report, Infrastructure Australia, November 2025, page 18.
[17] ISP Transmission Cost Database Tool: 2025 Update, GHD Advisory, May 2025, page 41.
[18] 2025 Electricity Network Options Report, Australian Energy Market Operator, August 2025, page 32.

2.4.1.1 Unprecedented cost increases

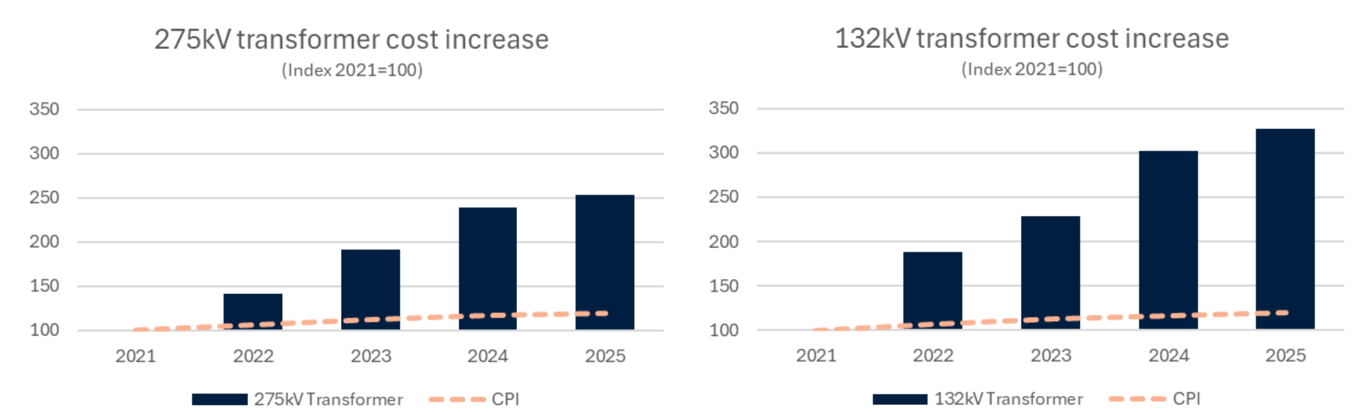
The United States Bureau of Labor Statistics tracks the producer price indices of a range of transmission-related equipment. The Electric Power and Specialty Transformer Manufacturing producer price index is shown in Figure 2.3 below[19] which illustrates that the price of transformers has increased substantially in the four years from 2021 to 2025. The scale of price increase over the last four years is unprecedented, equivalent to the cumulative price increase over the preceding 40 years.

Figure 2.3 - Historical United States transformer price index



These cost impacts are borne out by Powerlink's recent experience, with the price of transformers doubling over the last four years, significantly exceeding the Consumer Price Index (CPI) as shown in Figure 2.4.

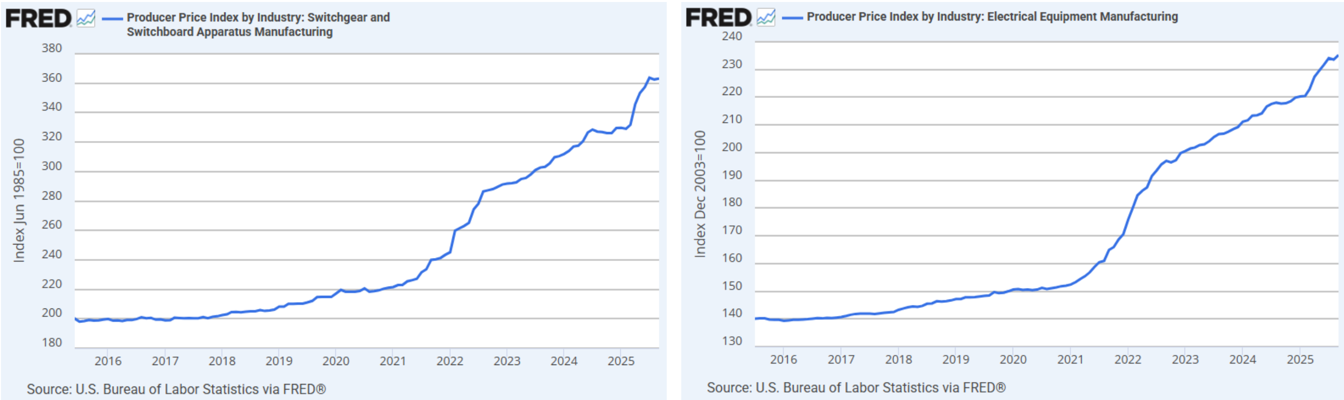
Figure 2.4 - Historical Powerlink transformer cost indices



[19] Producer Price Index by Industry: Electric Power and Specialty Transformer Manufacturing, US Bureau of Labor Statistics, retrieved from FRED (Federal Reserve Bank of St. Louis) on 29 December 2025.

Similar cost effects can be seen for switchgear and associated equipment[20, 21] as shown in Figure 2.5.

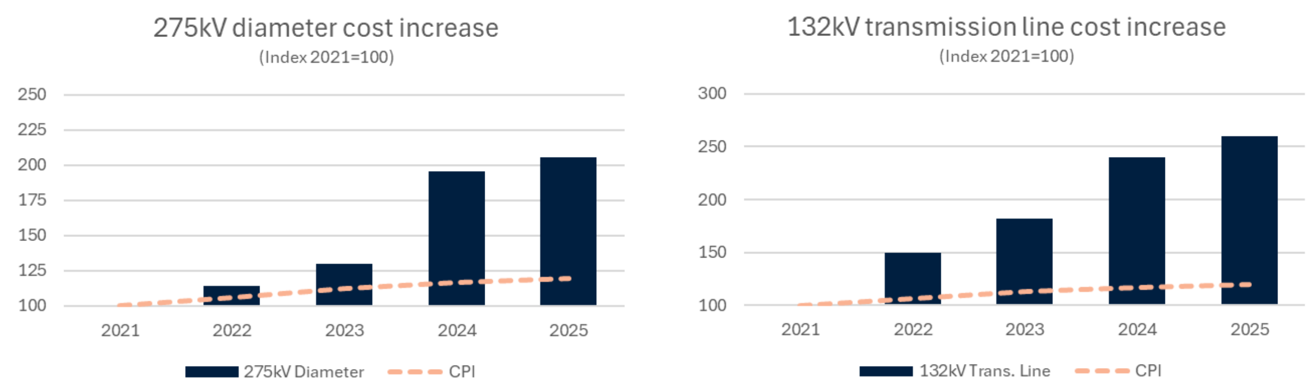
Figure 2.5 - Historical United States switchgear and equipment price indices



Composite cost metrics, which include contractor and internal labour costs in addition to plant and materials, illustrate the impacts of these increases on transmission development. Similar to the cost of major plant items, the cost of delivering transmission assets has doubled over the past four years.

Figure 2.6 shows the changes in delivered cost of a 275kV switchgear diameter in a substation and the delivered cost per kilometre of 132kV transmission line.

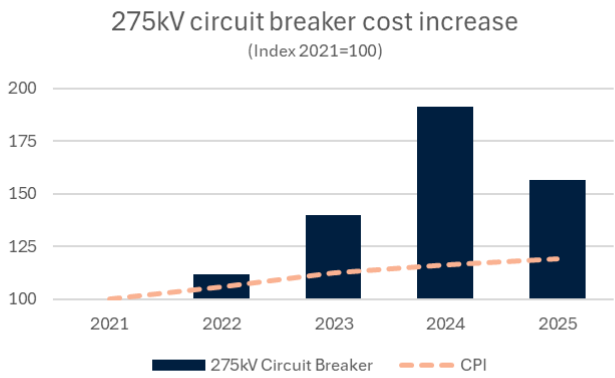
Figure 2.6 - Historical Powerlink composite cost indices



While significant global demand has driven costs upward and extended delivery timeframes for most transmission equipment types, we have sought to mitigate these impacts. For example, Powerlink has reduced the cost of 275kV circuit breakers by developing alternative supply options, as shown in Figure 2.7 below. Through proactive engagement, we negotiated for a key supplier to establish a new manufacturing facility in China, providing a lower cost and reducing the reliance upon the manufacturing plant in the United States.

[20] Producer Price Index by Industry: Switchgear and Switchboard Apparatus Manufacturing, US Bureau of Labor Statistics, retrieved from FRED (Federal Reserve Bank of St. Louis) on 29 December 2025.
[21] Producer Price Index by Industry: Electrical Equipment Manufacturing, US Bureau of Labor Statistics, retrieved from FRED (Federal Reserve Bank of St. Louis) on 29 December 2025.

Figure 2.7 - Historical Powerlink 275kV circuit breaker cost index



In 2022 Powerlink undertook a review of our approach to life extension, or refit, of transmission lines, namely our Asset Reinvestment Review. The review considered targeted investment in life extension of transmission line assets, which provided the opportunity to reprioritise our capital expenditure in the current 2022-27 regulatory period. The outcomes of this review underpin our forecast for the 2027-32 regulatory period, as highlighted in Chapter 4 Capital Expenditure.

2.5 Complexity

Powerlink has categorised the types of complexity impacting Powerlink's operating environment into two key categories – system complexity and deliverability.

System complexity encompasses changes in network demand and connectivity to the network, including increased cyber threats to the digital and telecommunications networks necessary to operate the transmission network. Overall, increased system complexity drives the need for a greater range of data that must be monitored in real time to operate the transmission network in a safe, reliable and cost-effective manner. This in turn requires more sophisticated technology, techniques and skills to be developed and implemented.

Deliverability encompasses those factors that can have a material impact on the cost and timeframe of projects, such as social licence to operate, workforce capacity and the regulatory environment. Deliverability influences the processes necessary to enable the cost-effective and timely completion of essential work to replace ageing assets and extend the transmission network.

2.5.1 System complexity

The transmission system is becoming more complex to operate. More than 11,100MW of large-scale renewable generation capacity, across 49 projects, has been added (or under construction) to the Queensland transmission network since 2018. In addition, approximately 8,000MW of rooftop solar is installed across Queensland[22].

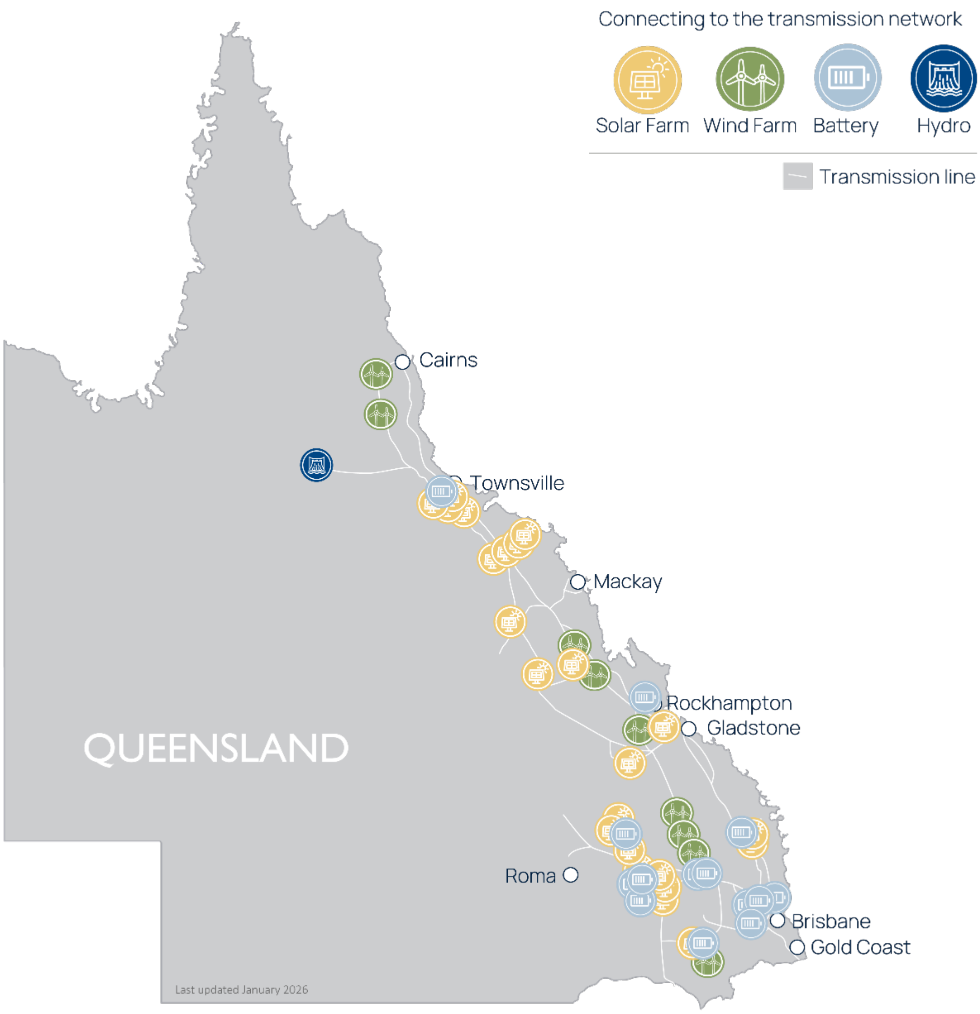
Figure 2.8 shows the number of current and completed connection projects (up to January 2026) and illustrates the increasing number of geographically dispersed generators, BESS and PHES connected to Powerlink's transmission network. This trend is expected to continue throughout the 2027-32 regulatory period.

It is important to note these connection projects are not regulated projects and their connection costs are not included in our Revenue Proposal expenditure forecasts. However, they may drive the need for additional

[22] Rooftop solar and storage report: January to June 2025, Clean Energy Council, September 2025, page 7.

investment in the prescribed transmission network, depending on the nature, number and location of connections and the timing of thermal generation retirements.

Figure 2.8 – Transmission connections since 2018



The increasing number of geographically distributed, inverter-based generators connected to the transmission network presents technical challenges in keeping electricity supply and demand balanced in real time. It also creates complexity in how we operate and plan the network. This is further complicated by generator connections within the distribution network that may impact transmission network performance or constraints. We work closely with Distribution Network Service Providers (DNSPs) Energex and Ergon Energy (part of the Energy Queensland group) through joint planning and other processes to identify and understand the impact of such generation within the distribution network.

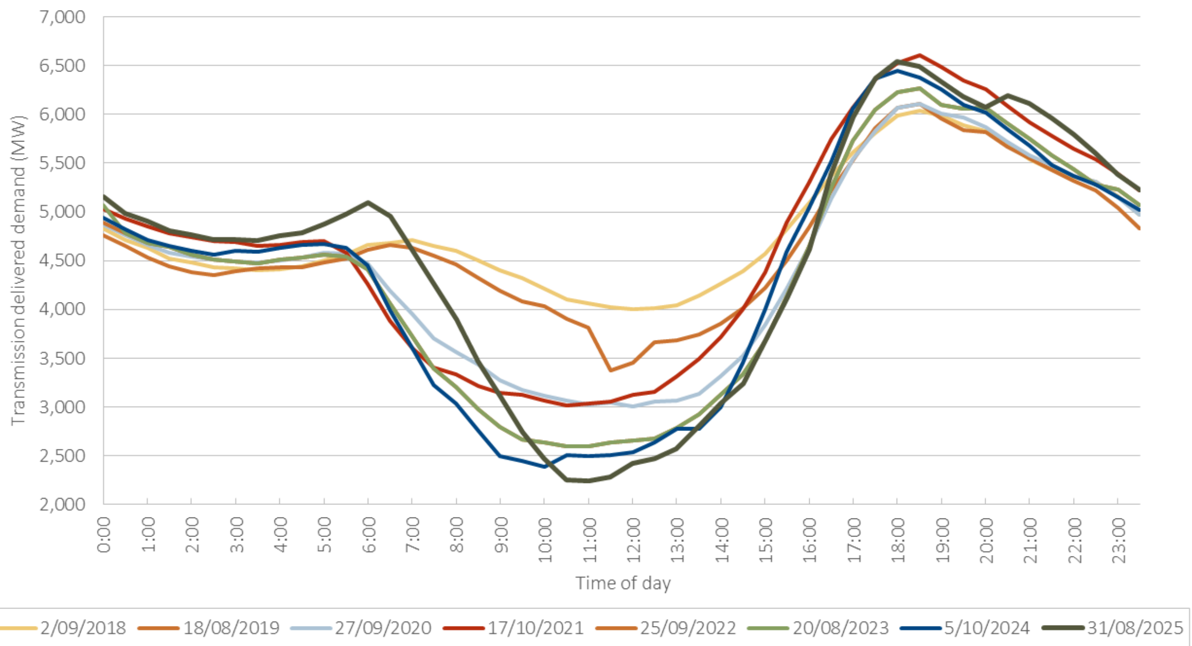
As the complexity of the system increases, the risk of unanticipated events in response to system disturbances increases. This requires increasingly complicated planning and scenario analysis to ensure that system disturbances can be mitigated within operational timeframes.

2.5.1.1 Operating envelope

A key driver of system complexity on the transmission network is the increasing operating envelope – the gap between maximum and minimum demand. This is especially challenging while planning and managing network outages to deliver work.

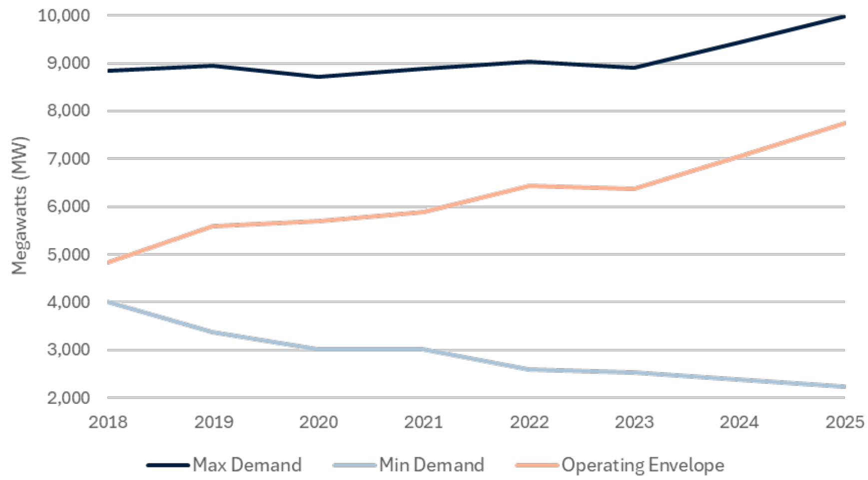
The increased operating envelope is predominantly due to the fall in minimum demand on the transmission network. Figure 2.9, from Powerlink's 2025 Transmission Annual Planning Report (TAPR), shows how minimum demand during the day has continued to decrease since 2018. This is driven by the significant uptake of rooftop solar, which contributes to meeting demand during daylight hours and results in a lower minimum demand on the transmission network.

Figure 2.9 - Changing minimum demand conditions (Source: Powerlink)



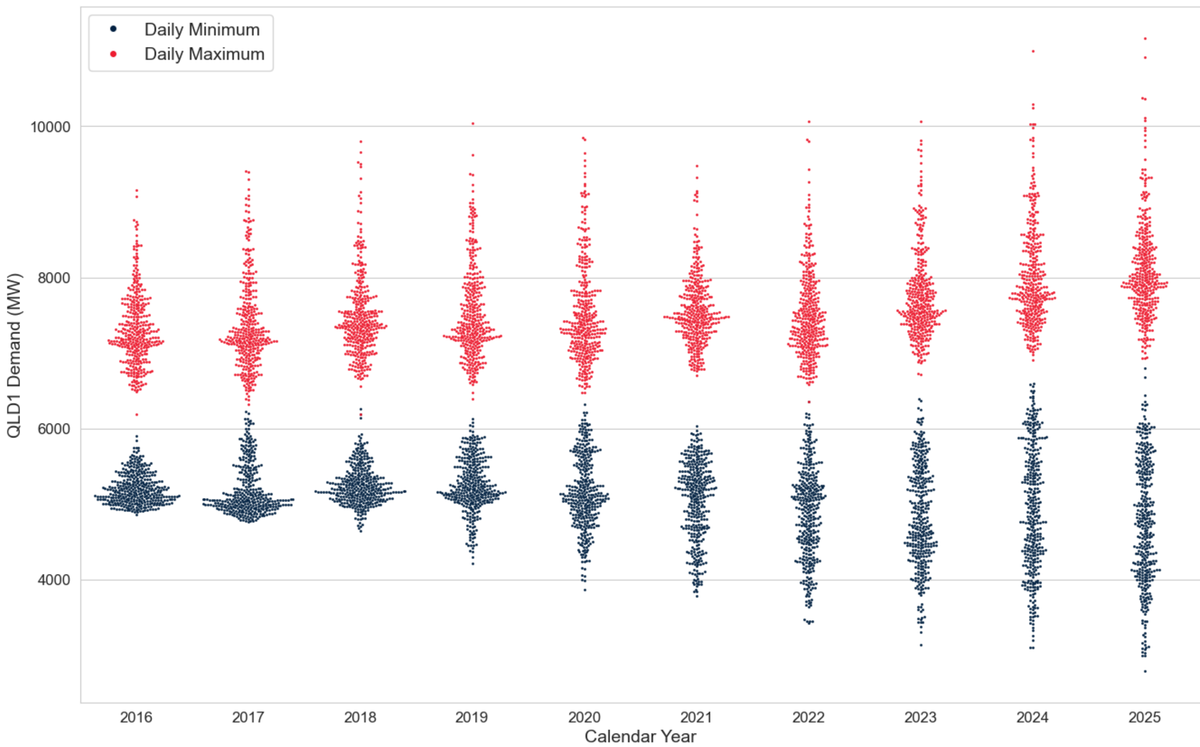
While minimum demand has fallen significantly, maximum demand has continued to increase. This means that the Queensland energy system's operating envelope has increased by almost 60% from 4,834MW in 2018 to 7,735MW in 2025, based on transmission delivered demand, as shown in Figure 2.10.

Figure 2.10 - Operating envelope – transmission delivered demand (Source: Powerlink)



In addition, the daily maximum and minimum demand is becoming more variable and less predictable, with an increasingly broad spread of values. This results in further complexity in operating and planning the network, as a far greater range of potential demand scenarios must be provided for, resulting in considerably more analysis and scenario planning. The increasing spread of maximum and minimum demand each year is shown in Figure 2.11, where the maximum and minimum operational demand for every day of the year is represented by a dot.

Figure 2.11 - Operating envelope – transmission operational demand (Source: Powerlink)



The operating envelope and its daily variability are contributing to increasingly dynamic operating conditions for the network, particularly for reactive plant such as Static Var Compensators, capacitors, reactors, and transformer tap-changers. Many of these assets were not originally expected to operate under such variable conditions, having been installed based on historical network assumptions.

The rapid increase in dynamic technologies such as batteries and inverter-based resources connected to the network add further complexity. These assets offer new opportunities to support system security services, including voltage control and inertia, but they are inherently variable in nature. Synchronous condensers, which provide protection-grade fault current, are also expected to play a critical role in delivering an underlying level of system strength services. While these technologies expand our toolkit, they also introduce a multi-faceted operational challenge.

We are committed to implementing the most efficient mix of tools, balancing capital investment with market-based solutions to manage complexity and deliver safe, reliable and cost-effective outcomes for customers and the market. Long duration storage, advanced energy management tools and operational forecasting capabilities will be key to managing the complexity and security of supply challenges during all variable conditions including minimum load scenarios. Operational forecasting tools will also support improved visibility of network conditions during planned outages.

Managing the security of the transmission network within the increasing operating envelope is a significant operational challenge and remains a key focus for Powerlink in the 2027-32 regulatory period.

2.5.1.2 Cyber security

As information technology and operational technology become increasingly integral to energy system operations, the risk of cyber attacks grows. Implementing robust cyber security measures, including threat detection, incident response, and regular assessments, is essential for safeguarding critical infrastructure.

As a Transmission Network Service Provider (TNSP), Powerlink is required to comply with the *Security of Critical Infrastructure Act 2018*, which includes mandatory reporting requirements and the development of risk management programs. The Act is a key driver for entities like Powerlink to enhance security and resilience against various threats by implementing measures to mitigate risks associated with cyber threats, espionage, and other security concerns.

We are advancing the cyber security of our network to protect against the rising level of emerging threats by aligning with the Australian Energy Sector Cyber Security Framework (AESCF). We are required to continue this focus in the 2027-32 regulatory period. We also work closely with the Australian Signals Directorate in cooperation with its Critical Infrastructure Uplift Program (CI-UP) which regularly provides advice and recommendations to further secure Powerlink's assets through targeted investments.

Our response to this increasingly complex environment includes enhancing physical security of sites as both a barrier measure for cyber security and protection of primary network assets. These issues drive further compliance obligations that must be considered when assessing the deliverability of our necessary works.

2.5.2 Deliverability

Powerlink, together with other network service providers, faces significant challenges in delivering safe, reliable and cost-effective transmission services. These challenges arise from the scale of work increasing demand for skilled resources, the need to secure and maintain social licence through the energy transition, the ongoing requirement to protect the environment and manage impacts and meeting additional regulatory and legislative obligations.

2.5.2.1 Workforce capacity and capability

Infrastructure Australia, in its Infrastructure Market Capacity Report, identified a significant uplift in infrastructure works in the five-year outlook period to 2028/29. It reports that the Major Public Infrastructure Pipeline has increased to $242 billion, with utilities investment having doubled to $36 billion compared to its 2024 report [23].

Construction activity for the 2032 Olympics and Paralympics is another factor Powerlink has considered in its future resource planning.

For the energy sector, the transition to net zero is expected to remain a key driver of investment, as ageing generating plant is progressively replaced. Infrastructure Australia, estimate the total pipeline, including public and private funding, for projects to build transmission, solar, wind and pumped hydro is now $163 billion for the five years to 2028/29[24]. This contributes to a significant demand for specialised workforce, with demand expected to peak in mid-2027, leading to a potential resource gap of up to 300,000[25] full-time equivalent positions.

Powerlink has adopted several strategies specifically aimed at securing sufficient workforce capacity and capability to enable delivery of its forecast portfolio of work, including the 2027-32 regulatory period.

- **Major Projects Division –** We have established a dedicated division to oversee the delivery of large projects within our capital expenditure program to ensure cost-effective delivery and robust governance throughout the project lifecycle.
- **Field delivery resource models –** We have expanded our regional workforce capacity in response to forecast increases in workload across central and northern Queensland. In parallel, we have secured a new Service Level Agreement with our maintenance service provider to ensure that field delivery resources are aligned with projected demand, supporting efficient and reliable network service delivery over the regulatory period.
- **Panel arrangements** – We are consolidating our transmission lines and substations outsourcing arrangements under a newly established panel agreement with delivery partners to support the efficient delivery of construction works. This enhanced framework will introduce additional delivery partners and incorporate scalable capacity provisions to accommodate future workload increases. The expanded panel structure is expected to foster competitive tension, improve cost efficiency, and support timely execution of capital works across the regulatory period.
- **Proactive staff attraction and retention –** We have focused on our recruitment and retention strategies and practices to secure the highly skilled workforce required, including increasing our early career programs (i.e. apprenticeship and graduate programs).

2.5.2.2 Social licence to operate

As a result of a changing energy system and related network development, impacts are being felt in regional and rural communities. Stakeholders impacted by energy infrastructure development, including transmission, seek to influence and shape how change occurs, limit negative impacts, and deliver positive economic and social outcomes.

Neglecting community expectations and a lack of community acceptance of transmission infrastructure projects can lead to significant challenges, including project delays, increased costs, and strained relationships with stakeholders. Powerlink considers proactive engagement and investment is essential to mitigating these risks. Communities, landholders and Traditional Owners are key stakeholders in Powerlink's activities.

[23] Infrastructure Market Capacity 2025 Report, Infrastructure Australia, November 2025, pages 5-6.
[24] Infrastructure Market Capacity 2025 Report, Infrastructure Australia, November 2025, page 28.
[25] Infrastructure Market Capacity 2025 Report, Infrastructure Australia, November 2025, pages 43-44.

Social licence to operate has emerged as an increasingly critical enabler of project delivery, influencing planning, engagement and investment decisions. Social licence (the acceptance by stakeholders of our operations within their community) is critical for Powerlink to successfully construct and maintain our network over the life of the assets. We expect this to continue to be a critical enabling activity into the 2027-32 regulatory period.

The requirement to recognise and achieve strong social licence to operate has informed changes to the Rules and supporting regulations. The National Electricity Amendment (Enhancing community engagement in transmission building) Rule 2023 came into effect in December 2023[26]. Consistent with the long-held view of TNSPs, the Australian Energy Market Commission (AEMC) identified that social licence is critical to the timely delivery of the major transmission infrastructure required for the energy transition. The rule benefits consumers by supporting the timely delivery of the transmission needed to connect cheaper renewable generation to customers[27].

Community expectations in relation to developing new energy infrastructure continues to shape government policy. In 2025, the Queensland Government implemented changes to the *Planning Act 2016,* introducing a Community Benefit System that includes mandatory social impact assessments and community benefit agreements for new solar, wind and BESS developments.

Powerlink had already embedded social performance as a core management system. We actively engage communities, landholders and Traditional Owners in our transmission easement planning process, avoid or manage social impacts, and seek to deliver enduring benefits that create a positive legacy beyond project completion. This approach aligns with the Energy Charter's Better Practice Social Licence Guideline, our strategic objectives and regulatory requirements, supporting a positive social licence to operate for Powerlink and long-term value for Queensland communities.

We have progressed initiatives to improve our approach to early engagement, corridor selection processes and community benefit and social value investment including uplifts in landholder and neighbour payments, establishing Indigenous partnership agreements and undertaking social impact assessments. These considerations inform our forecast for capital expenditure (refer Chapter 4 Capital Expenditure).

2.5.2.3 Environment

Climate resilience has been identified as a key concern by our customers (refer Section 2.3.3). We will continue to adopt proactive approaches to managing the network as conditions change, address wider environmental protections, and comply with relevant legislation. This includes related reporting requirements, which may lead to additional initiatives and obligations.

We are also seeking collaborative approaches in complying with legislation, such as the *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act). We have been working closely with the Commonwealth Department of Climate Change, Energy, the Environment and Water (DCCEEW) to support better collaboration, culminating in a Memorandum of Understanding between Powerlink and DCCEEW in October 2024.

[26] National Electricity Amendment (Enhancing community engagement in transmission building) Rule, Australian Energy Market Commission, November 2023.
[27] Rule Determination National Electricity Amendment (Enhancing community engagement in transmission building) Rule, Australian Energy Market Commission, November 2023, Page 35.

Beyond the complexities of environmental compliance requirements, extreme weather events in Australia and across the world have placed upward pressure on insurance premiums. We continue to engage directly with insurance underwriters, our customers and the AER to propose appropriate insurance policies, excess levels and premiums. Further information on our proposed approach to insurance is provided in Chapter 5 Operating Expenditure.

2.5.2.4 Energy market regulation

The NEM regulatory environment continues to change. Key consultations recently concluded, underway, or expected to soon commence relevant to electricity transmission include:

- system security reforms, such as the AEMC's Improving Security Frameworks for the Energy Transition Rule change, and the pending Security Framework Enhancements Rule change proposal
- broader regulatory reform, such as the Electricity Network Regulation Review and the Integrated System Plan Framework (ISP) Review, and
- incentive schemes, including the Service Target Performance Incentive Scheme (STPIS) Review.

The outcomes of these consultations could have material impacts on our operations, such as changes to funding models for future network investment and the way revenue is collected, which could affect the project development lead time or time to deliver necessary works. We proactively provide input into these processes, with the outcome determined by the various bodies involved.

We will implement any changes required. However, until we know the scope and scale of these, it will be difficult to estimate the cost impacts on the business. As a result, we have not allowed for changes in our operating expenditure forecast that may result from in-progress regulatory processes (refer Chapter 5 Operating Expenditure). If material costs are likely to be incurred, we may seek a cost pass through (refer Chapter 11 Pass Through Events).

2.5.2.5 Federal and Queensland Government policies

As a Government Owned Corporation, Powerlink must be responsive to the requirements and policy settings of the Queensland Government. We continue to work closely with Queensland Treasury, and across the Queensland Government more broadly, to engage on future policy settings. The Queensland Government’s Energy Roadmap, published in October 2025, utilised Powerlink modelling and data to help shape its direction and future planning.

Relevant policies from both the Queensland Government and the Federal Government that could affect our Revenue Proposal have been considered and no additional policies have been identified that may impact our submission. We will continue to maintain ongoing oversight of emerging policy and legislative developments throughout the revenue determination process.

3 Customer Engagement

3.1 Introduction

This chapter outlines Powerlink's customer engagement activities and how these influenced the development of our 2027-32 Revenue Proposal.

Key highlights:

- Input from customers and other stakeholders shaped every major element of our engagement approach and plan.
- The engagement scope, schedule and participation levels were co-designed with our Customer Panel, Australian Energy Regulator (AER), government, and other stakeholders, including members of the AER's Consumer Challenge Panel (CCP34).
- We ran an expression of interest to form our Revenue Proposal Reference Group (RPRG), a subset of our Customer Panel, and established an independent Chair, to engage more intensively and deeply on key aspects of the Revenue Proposal.
- The breadth of our engagement was extended following RPRG feedback, and we sought the views of Queensland households, as well as commercial and industrial load customers.
- Our Transmission Network Forums, Queensland Household Energy Survey, and commercial and industrial load customer survey brought new voices and priorities into the process, with input from more than 4,000 households and 700+ customers and stakeholders.
- Our Engagement Plan and schedule was shaped by RPRG feedback, including meeting agendas, priorities and additional sessions.
- RPRG members were provided with six updates on forecasts for capital and operating expenditure across eleven meetings during 2025.
- Input and feedback from this engagement directly influenced several aspects of our Revenue Proposal, including:
    - capable of acceptance criteria, which were developed collaboratively with the RPRG
    - operating expenditure forecast, including empowering the RPRG to select the output growth measures used in our trend calculation
    - capital expenditure forecast, with deep dives into Powerlink's project identification, estimating, lessons learnt and portfolio deliverability
    - empowering the RPRG to determine the approach Powerlink applied to smoothing the indicative price path to reduce the initial price impact and improve the predictability of increases over the remainder of the regulatory period
    - transparency of potential price impacts for other material transmission works considered outside the Revenue Proposal, and
    - approach to the Demand Management Innovation Allowance Mechanism (DMIAM) – based on RPRG advice, Powerlink has not sought this allowance.
- Our approach to engagement has resulted in high levels of influence and satisfaction from our RPRG and broader Customer Panel, with 100% of RPRG members satisfied with the quality of information, their influence, level of engagement, and overall management of the process, and engagement key performance indicators were exceeded for both the RPRG and the Customer Panel.

3.2 Our engagement approach

3.2.1 Overview

Powerlink has a long history of strong engagement with our customers and other stakeholders. Genuine and timely engagement informs our decision making as part of normal business operations. It is fundamental to the way we do business and has consistently delivered improved outcomes for our customers and other stakeholders.

Our purpose is to serve Queenslanders and provide world-class transmission services that are safe, reliable and cost-effective. We are a founding signatory of The Energy Charter [28]and strive to align with the Charter's principles, in particular Principle One – *we will put customers at the centre of our business*.

As our operations stretch across Queensland, we regularly engage with a diverse range of stakeholders, including our customers, landholders, environmental, cultural and community groups, government agencies and industry bodies, including the AER.

Our engagement is designed to create a shared understanding of our operating environment to inform future decisions and the trade-offs involved, e.g. cost, reliability. This engagement occurs as part of business as usual (BAU) through:

- our Customer Panel, which meets at least three times a year and provides input on our activities to inform our decision making across a broad range of areas, e.g. the business environment, growing network complexity and Regulatory Investment Test for Transmission (RIT-T) assessments
- our annual Transmission Network Forum, a flagship engagement activity, which typically involves more than 600 stakeholders across a range of groups
- our Central Queensland Transmission Network Forum for engaging directly with regional stakeholders
- the dedicated teams that engage directly with communities and landholders impacted by Powerlink projects, as well as our ongoing maintenance activities
- targeted webinars and workshops on RIT-Ts, network connections, regional developments, demand and energy forecasts, and
- regular direct briefings to government, industry and community representatives across Queensland about our operations in their areas.

3.2.2 Engagement goal

Powerlink's engagement goal remains:

To deliver a Revenue Proposal that is capable of acceptance by our customers, the AER and Powerlink.

This overarching objective provided the 'north star' for the development of Powerlink's previous Revenue Proposal for the 2022-27 regulatory period. It created greater focus, innovation, collaboration and constructive discomfort within the business, with our customers, stakeholders and the AER. Based on circumstances at that time, Powerlink's expenditure forecasts showed a small reduction in capital expenditure and no real growth in operating expenditure. As a result, the AER in its Draft Decision considered Powerlink's 2023-27 Revenue Proposal was capable of acceptance in all material respects.

By retaining this goal, we have continued to test and challenge our expenditure forecasts and key positions included in this Revenue Proposal. We are of the view our Revenue Proposal is capable of acceptance as an overall package and is in the long-term interests of customers.

[28] The Energy Charter - https://www.theenergycharter.com.au/

Further information on capable of acceptance is provided in Section 3.5.

3.3 Engagement planning

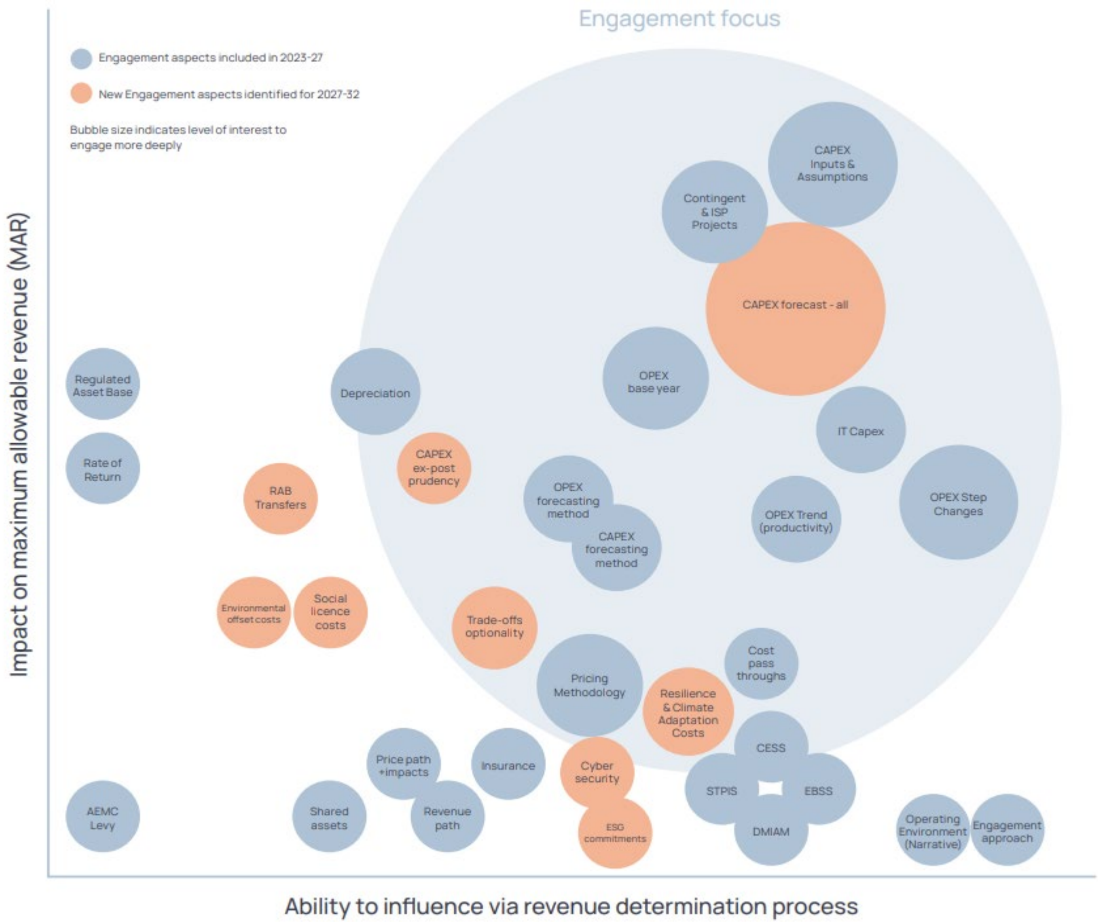
3.3.1 Engagement scope co-design process

A clear scope allows all stakeholders to better allocate time, energy and resources to the areas of the Revenue Proposal that have a material impact and can be influenced through engagement.

Powerlink held a co-design workshop on 26 November 2024 to help establish the scope of engagement for our 2027-32 Revenue Proposal. The workshop comprised representatives from Powerlink's Customer Panel, the AER, including a member of its Board, the AER's Consumer Challenge Panel, Queensland Government, as well as senior Powerlink representatives, including members of the Executive and Board.

At the session, participants proposed elements they considered would have the greatest impact on Powerlink's Maximum Allowed Revenue (MAR) and mapped these against their potential to be influenced through engagement. As engagement on the revenue determination process has progressed and actual impact on MAR has been quantified, some scope elements have been repositioned. The resulting scope of engagement for Powerlink's 2027-32 Revenue Proposal from the co-design workshop is shown in Figure 3.1.

Figure 3.1 - Engagement scope



3.3.2 IAP2 Spectrum Participation Level

We plotted the outputs of the co-design workshop against what we considered to be the appropriate level of engagement in the International Association for Public Participation (IAP2) Spectrum in Table 3.1.

Table 3.1 - IAP2 Spectrum Participation Level

IAP2 Spectrum Level of Engagement	Aspect of Revenue Proposal
Empower – to place final decision making in the hands of customers and stakeholders.	• Operating expenditure – trend (output change) • Price path impacts
Collaborate – to work together with our customers and other stakeholders to formulate alternatives and incorporate their advice into final decisions to the maximum possible extent.	• Engagement approach (Engagement Plan) • Operating environment (Business Narrative) • Demand Management Innovation Allowance Mechanism (DMIAM) • Capable of acceptance criteria
Involve – to work directly with customers and stakeholders to ensure their concerns and aspirations are directly reflected in the alternatives developed.	• Capital expenditure – inputs and assumptions • Capital expenditure – contingent and ISP projects[29] • Capital expenditure – business IT • Capital expenditure – trade-offs and optionality* • Operating expenditure – step changes • Operating expenditure – trend (price change & productivity change)
Consult – to obtain feedback on alternatives and draft proposals.	• Capital expenditure forecasting methodology • Capital expenditure – forecast, inc. reinvestment and augmentation* • Capital expenditure – ex post prudency* • Capital Expenditure Sharing Scheme (CESS) • Cost pass throughs • Cyber security* • Depreciation • Efficiency Benefit Sharing Scheme (EBSS) • Insurance • Operating expenditure forecasting methodology • Operating expenditure – base year • Service Target Performance Incentive Scheme (STPIS)
Inform – to provide balanced information to keep customers and stakeholders informed.	• Environmental offset costs* • Social licence costs* • Australian Energy Market Commission (AEMC) Levy • Regulatory Asset Base (RAB) • RAB transfers* • Rate of return • Revenue path • Shared assets • Pricing methodology • Environmental, Social and Governance (ESG) commitments* • Resilience and climate adaptation*

Increasing level of influence on decision

* New engagement aspects identified for our 2027-32 revenue determination process.

[29] An augmentation project identified on the Optimal Development Path in the Australian Energy Market Operator's Integrated System Plan.

The outputs of the workshop were directly incorporated into Powerlink's Engagement Plan, which was first produced as a draft in November 2024 for feedback by the RPRG. The plan was initially finalised in January 2025 and then updated in June and December 2025 reflecting Powerlink's dynamic approach to engagement.

Further detailed information on aspects of our Revenue Proposal engagement is provided in our Engagement Plan, included as Appendix 3.01.

3.3.3 Powerlink's Customer Panel and Revenue Proposal Reference Group

Powerlink's Customer Panel is well established, having been formed in May 2015 to make a positive step-change in our engagement activities. Our Customer Panel has played, and will continue to play, a primary role in informing our business decisions, including the development of Powerlink's Revenue Proposal.

In late 2024, Powerlink established a RPRG as a subset of our Customer Panel. The RPRG is an advisory body that meets frequently (every 4-6 weeks) throughout the revenue determination process. This allowed for detailed discussion on important matters, as well as testing positions that shaped our Revenue Proposal.

This group reports back to the broader Customer Panel and assists in ensuring that our Revenue Proposal is aligned with customer expectations. Powerlink prepared a Terms of Reference, included as Appendix 3.02, for the RPRG and sought initial interest from Customer Panel members in mid-2024. The group met formally for the first time in February 2025 and a further 10 times prior to lodgement of our Revenue Proposal.

More information on the members and role of both the Customer Panel and the RPRG is included in Appendix 3.01 Engagement Plan and Appendix 3.02 RPRG Terms of Reference.

3.3.4 Powerlink senior management engagement

Powerlink's senior leadership team recognises the importance of genuine engagement and hearing the voices of customers and other stakeholders directly. Our Executives regularly attend Customer Panel meetings, either as presenters or observers, to listen and gain a better appreciation of what is important to customers and why. Powerlink Board members also attend Customer Panel meetings for similar reasons.

This approach extends to the RPRG meetings, where all meetings to date were attended by at least one or more of Powerlink's Executives. The Executive General Manager Network Investment has attended all meetings while our Chief Executive attended the majority of the meetings to date.

In addition, Powerlink has brought in a range of General Managers and subject matter experts to enable direct engagement with our RPRG and Customer Panel members.

3.4 Engagement timeline

The RPRG met monthly since February 2025, and all meeting records are on Powerlink's website[30]. RPRG members were provided six updates on forecasts for capital and operating expenditure across eleven meetings during 2025.

A timeline of engagement activities is shown in Figure 3.2. Engagement will continue throughout 2026.

[30] https://www.powerlink.com.au/customer-panel

Figure 3.2 - Engagement activities and timeline relating to 2027-32 Revenue Proposal

Year	Month	Activity
2024	JUNE	**Customer Panel meeting** - Regulatory timeframes and initial engagement proposal
	SEPTEMBER	**Revenue Determinations 101** - Introductory training session to new members of our Customer Panel
	NOVEMBER	**Revenue Determination Scoping Workshop** - Co-design of engagement scope with critical stakeholders
2025	FEBRUARY	**RPRG meeting 1 -** Initial expenditure forecasts
	MARCH	**RPRG meeting 2 -** Capital and operating expenditure forecasting methodologies
	APRIL	**Customer Panel meeting -** RPRG member report back and criteria for capable of acceptance **RPRG meeting 3 -** Capital expenditure forecasting methodology (additional meeting in response to RPRG feedback)
	MAY	**RPRG meeting 4 -** Updated expenditure forecasts **Queensland Household Energy Survey -** Two additional questions to inform the 2027-32 Revenue Proposal
	JUN E	**RPRG meeting 5 -** Cyber security and business IT expenditure forecast and contingent projects **Customer Engagement Survey -** Powerlink reached out to directly connected and C&I customers[31]
	JULY	**Customer Panel meeting -** RPRG member report back and updated expenditure forecasts **RPRG meeting 6 -** Operating expenditure base year, step changes and trend
	AUGUST	**RPRG meeting 7 and Powerlink Substation and Control Room Site Tour** – depreciation and review of actions **Central Queensland Transmission Network Forum**
	SEPTEMBER	**RPRG meeting 8** – Overview of draft Revenue Proposal **Customer Panel meeting** – Overview of draft Revenue Proposal
	OCTOBER	**RPRG meeting 9** – Operational Technology and related programs, incentive schemes
	NOVEMBER	**RPRG meeting 10** – Insurance, non-network property, lessons learnt and project deliverability **Annual Transmission Network Forum**
	DECEMBER	**RPRG meeting 11** – Updated expenditure forecasts, engagement report back

[31] We defined commercial & industrial (C&I) customers as Energy Queensland customers in the following tariff classes – Individually Calculated Customers (ICC), Connection Asset Customers (CAC), and Standard Asset Customers (SAC) Large. This includes all customers connected at 11kV and above, and those connected at low voltage that have an annual energy consumption of 100MWh or more.

3.5 Capable of acceptance criteria

The AER's Better Resets Handbook[32] provides guidance on its expectations with a view to encouraging networks to develop high quality revenue proposals through genuine engagement with customers. While this ongoing engagement delivers signifcant benefits to a network operator, the AER notes that high quality proposals should increase the efficiency of the regulatory process, allowing more issues to be settled at the Draft Decision stage so that proposals may be fully accepted[33].

The AER identifies three criteria to assess the engagement undertaken – *the nature of engagement, breadth and depth of engagement, and clearly evidenced impact of the engagement*. These criteria are set out in Table 3.2 and are consistent with those applied by the AER to assess the capability of acceptance of Powerlink's 2023-27 Revenue Proposal.

The RPRG proposed further engagement on what capable of acceptance could mean for customers. To enable this, we developed the criterion below.

3.5.1 Proof point criterion

Powerlink proposed a proof point criterion to the RPRG that reflects the context of the current and forecast operating environment, namely:

> *Reasonable operating and capital expenditure forecasts are proposed that reflect prevailing conditions, and are:*
>
> - *underpinned by appropriate and transparent forecasting methodologies*
> - *supported by clear explanations as to why forecasts are different from historical expenditure*
> - *have regard to the AER's top-down analysis of expenditure, and*
> - *align with the AER's expectations for capex, opex and regulatory depreciation stated in the AER's Better Resets Handbook.*

Following input and feedback from the RPRG on this matter, the proof point above was agreed as being suitable for Powerlink's 2027-32 Revenue Proposal.

3.5.2 Framework for application of the criteria

We recognise that the RPRG and Customer Panel do not have the capability to assess all aspects of the capable of acceptance criteria as defined. We worked with the RPRG to develop a matrix to clarify the expectations of which party would comment on each of the criteria. This capable of acceptance criteria matrix is provided in Table 3.2.

Table 3.2- Capable of acceptance criteria

Capable of Acceptance Criteria	Customer Panel	AER	Powerlink
Nature of engagement	Yes	Yes	Yes
Breadth and depth	Yes	Yes	Yes
Clearly evidenced impact	Yes	Yes	Yes
Proof point	Optional	Yes	Yes

32 Better Resets Handbook - Towards Consumer Centric Network Proposals, Australian Energy Regulator, July 2024.
33 Better Resets Handbook - Towards Consumer Centric Network Proposals, Australian Energy Regulator, July 2024, page 3.

3.5.3 Powerlink self-assessment against the capable of acceptance criteria

Table 3.3 details our self-assessment against the capable of acceptance criteria for the 2027-32 Revenue Proposal.

Powerlink considers that we have met all criteria and that this Revenue Proposal provides the evidence summarised in Table 3.3.

Table 3.3 - Capable of Acceptance self-assessment

Criteria	Assessment	Evidence

Nature of engagement	• Sincerity of engagement
	• Consumers as partners
	• Equipping customers
	• Accountability
	(AER Better Resets Handbook)
		• Powerlink co-designed the engagement approach and scope with the Customer Panel and other key stakeholders, including government, the AER and the AER's Consumer Challenge Panel.
		• The capable of acceptance criteria were developed collaboratively with the RPRG.
		• Every RPRG meeting has been attended by:
		  ○ between one and four executives, including the Chief Executive
		  ○ AER CCP34 members
		  ○ representatives of the AER.
		• Six out of 35 scope elements have been raised to the empower or collaborate level on the IAP2 spectrum.
		• We ran a 'Revenue Determination 101' session in 2024 to develop the knowledge and understanding of new members of the RPRG/Customer Panel to maximise engagement participation and insights.
		• The RPRG Terms of Reference sets out all governance and remuneration arrangements for participants.
		• Meeting presentations, additional information and meeting notes (with clear actions identified) are published on our website.
		• RPRG meeting agendas were informed by member preferences and Powerlink has committed to ongoing engagement.

Criteria	Assessment	Evidence

Breadth and depth	• Accessible, clear and transparent engagement
	• Consultation on desired outcomes and the inputs
	• Multiple channels of engagement
	• Customers' influence on the proposal
	(AER Better Resets Handbook)
		• Powerlink's Engagement Plan outlines engagement objectives, scope elements and the level of participation and influence for each element. This was developed collaboratively with our customers and other stakeholders and published in January 2025.
		• Our Engagement Plan was updated in line with emerging priorities and preferences of the RPRG, and revised in June 2025 and December 2025.
		• We engaged directly with the RPRG on our Expenditure Forecasting Methodology prior to its lodgement with the AER.
		• We routinely provided the RPRG and Customer Panel with direct access to executives, senior managers and other relevant subject matter experts.
		• We widened the breadth of our engagement to ensure the views of all customers (households, generators, commercial and industrial loads) were considered. Channels of engagement included:
		  ○ detailed, frequent meetings with the RPRG and Customer Panel
		  ○ publication of a draft Revenue Proposal, and overview, with opportunity to make a submission or provide feedback
		  ○ a dedicated presentation at the Central Queensland Transmission Network Forum held in Gladstone
		  ○ dedicated questions in Queensland Household Energy Survey
		  ○ survey of large energy demand customers (C&I).
		• Multiple channels of engagement have been used including:
		  ○ face-to-face meetings
		  ○ larger engagement forums
		  ○ market research surveys
		  ○ site tours
		  ○ website
		  ○ social media.
		• All topics discussed were referenced against the IAP2 spectrum to indicate the level of influence.
		• Powerlink consistently asked the RPRG and Customer Panel to test and challenge assumptions with six of 35 elements raised to empower or collaborate level on the IAP2 spectrum.
		• Actions from all RPRG meetings were clearly documented and responded to.

Criteria	Assessment	Evidence
Clearly evidenced impact	• Proposals linked to consumer preferences • Independent consumer support for the proposal (AER Better Resets Handbook)	• Section 3.7 of this chapter outlines how customer feedback has influenced the Revenue Proposal. • Market research identified customer priorities that have shaped this Revenue Proposal. • We published a draft Revenue Proposal in September 2025 and invited feedback via an online form, email and in-person at our Transmission Network Forum. • The RPRG provided a submission on the draft Revenue Proposal, engagement process and outcomes. • Powerlink responded to the RPRG submission by tailoring the agenda items of the subsequent three RPRG meetings to address its questions and concerns. We also published two RPRG briefing papers to provide further information on the alternative output growth measures and the alternative CESS calculation approach. • Where customers were not supportive of Powerlink's positions in the draft Revenue Proposal, those positions were reconsidered and adjusted where appropriate (refer Appendix 3.03). • The RPRG provided a statement in support of the quality of engagement undertaken by Powerlink (refer Section 3.81 and Appendix 3.06).
Proof point	Reasonable operating and capital expenditure forecasts are proposed that reflect prevailing conditions, and are: • underpinned by appropriate and transparent forecasting methodologies • supported by clear explanations as to why forecasts are different from historical expenditure • have regard to the AER's top-down analysis of expenditure, and • align with the AER's expectations for capital and operating expenditure and regulatory depreciation stated in the AER's Better Resets Handbook. (Powerlink definition – refer Section 3.5.1)	• Powerlink prepared a Business Narrative to provide insights into the current and future operating environment. • We engaged directly with the RPRG on our Expenditure Forecasting Methodology prior to lodging it with the AER. • We continued to engage with the RPRG on expenditure forecasts and associated processes, including lessons learnt and deliverability assessment of the portfolio of work. • We presented six forecasts over 11 months with an explanation of changes between forecasts – addressing capital and operating expenditure, revenue and price impacts. • Our expenditure forecasts reflect the unprecedented cost increases in the current regulatory period – future growth is in line with historical average. • We provide explanations of why forecasts are different from historical expenditure in this Revenue Proposal. • Powerlink presented benchmarking outcomes to the RPRG, explaining reasons for historical performance and expected future performance. • We engaged with the RPRG in August 2025, detailing no material change to our approach to depreciation from our previous Revenue Proposal. • Powerlink's positions and assumptions consider AER analysis, approaches and expectations set out in the AER's Better Resets Handbook.

3.6 End-user and stakeholder engagement

Early in the engagement process, the RPRG recommended Powerlink engage a broader representation of stakeholders, including Queensland households and commercial and industrial (C&I) energy users that are connected directly to Powerlink's transmission network or to the distribution network.

3.6.1 Commercial and Industrial load customer engagement

Powerlink initiated a dedicated engagement program for this customer segment.

- Hosting an interactive engagement session on the Revenue Proposal at Powerlink's inaugural Central Queensland Transmission Network Forum in Gladstone in August 2025.
- Undertaking an Expression of Interest (EOI) process with over 600 direct-connect and C&I customers to participate in a survey to understand the strategies and other factors that will shape their electricity use, allowing Powerlink to calibrate our own strategies, plans and forecasts to respond to their evolving needs.
- One-on-one engagement with Powerlink's directly connected customers as part of BAU practices and as requested.

Key insights from this engagement included:

- **Cost and price predictability** – predictable and transparent pricing is as critical as affordability for commercial and industrial customers, who seek to avoid sudden cost changes, particularly increases.
- **Investment preferences** – there is support for targeted, timely investment to meet future needs to avoid disproportionate cost impacts on existing C&I customers. Predictability in pricing and network upgrades are fundamental to long-term planning for industrial customers.
- **Electrification and emissions reduction** – most respondents are advancing electrification and energy efficiency to meet emissions targets. Approaches differ across sectors.
- **Demand expectations** – industrial customers foresee greater reliance on the transmission network as they electrify core processes and introduce new loads. Commercial customers expect their grid demand to remain steady or increase gradually alongside on-site renewables, batteries, and small-scale electrification.
- **Load profiles and flexibility** – commercial loads connected at the distribution network tend to be smaller, more flexible, and better suited to demand management technologies.
- **Customer priorities** – commercial customers value peak and nighttime reliability, with stronger emphasis on resilience through self-supply options (e.g. batteries, backup generation). Industrial users consider the grid a critical backbone, requiring additional capacity, reliability, and a cleaner energy supply.

3.6.2 Queensland Household Energy Survey

Each year, Powerlink and Energy Queensland undertake the Queensland Household Energy Survey (QHES)[34], to gain insights from more than 4,000 households across the State.

Powerlink leveraged input from the RPRG to design two new questions which were added to the QHES in 2025 to help inform the Revenue Proposal. The questions aimed to gauge support for investment in the network and identify which long-term benefits of upfront investment are most important to residential customers.

The results of the survey indicate that more than 57% of surveyed households support upfront investment in the power system for long-term benefits. Less than 7% are opposed and the remainder are neutral or require further

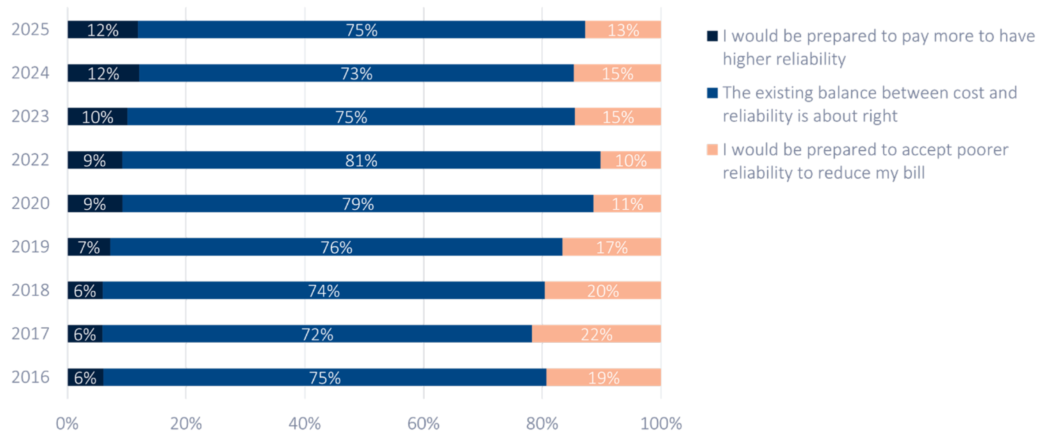
[34] https://www.powerlink.com.au/community/stakeholder-engagement/customer-research

information to form an opinion. A range of benefits are valued, with the most important benefits identified by respondents being affordability, reliability and resilience, as discussed in Chapter 2 Operating Environment.

Survey results also showed reliability has continued to grow in importance over time and household trust in energy suppliers to provide a reliable system hit an all-time high of 76% in 2025, up from 71% in 2024. Households that perceive energy suppliers are working to make energy more affordable decreased slightly from 38% in 2024 to 36% in 2025.

Figure 3.3 charts the QHES data on the balance between cost and reliability from 2016 to 2025.

Figure 3.3 - Balance of cost and reliability 2016-2025



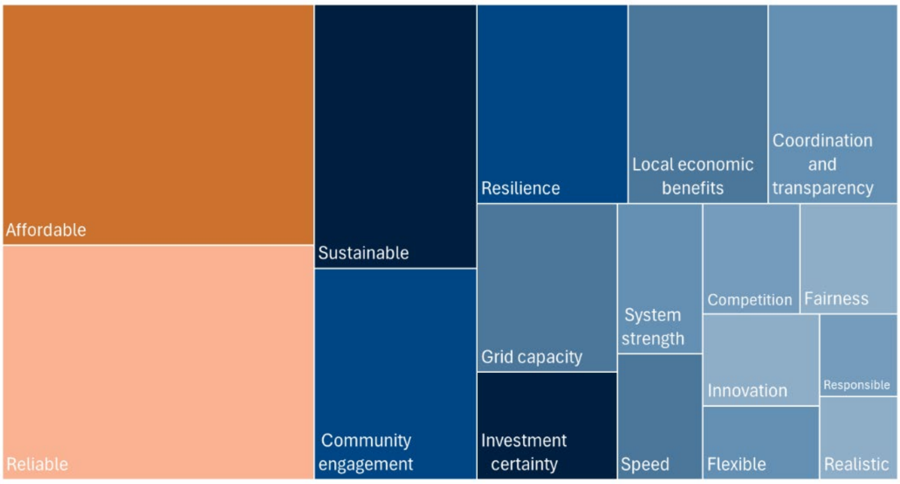
3.6.3 Transmission Network Forums

Powerlink hosted its first ever Central Queensland Transmission Network Forum in Gladstone in August 2025 to broaden its engagement and allow regionally based stakeholders the opportunity to engage directly with key Powerlink staff, including Executives.

We hosted an interactive activity to gather the views of 69 attendees. The forum attendees comprised approximately one-third directly connected customers (17% generation and 16% load) and two-thirds government, community and industry representatives. When asked what Powerlink should focus on as we develop our long-term investment plans, this group also prioritised affordability and reliability. Sustainability, community, resilience, local economic benefit, coordination and grid capacity also featured strongly.

Figure 3.4 shows the relative frequency of different responses, with a larger box indicating more frequent occurrence of the issue.

Figure 3.4 - Priorities for attendees at the Central Queensland Transmission Network Forum (August 2025)



Notably, government representatives, generation and load customers ranked reliability as more important than affordability by a small margin.

Powerlink's annual Brisbane-based Transmission Network Forum in November 2025 saw record attendance with more than 700 participants. An interactive table discussion focused on the provision of information for network planning and decision making. Input by attendees indicated that while stakeholders value the range of technical, operational and strategic information already provided by Powerlink, there is a desire for greater accessibility and targeted insights for different stakeholders. This outcome reinforces the importance of transparency and information sharing between Powerlink and its increasingly diverse stakeholder groups to enable effective decision making.

Forum presentations and documentation are published on our website[35].

3.6.4 Powerlink Stakeholder Perception Survey

Powerlink has conducted regular Stakeholder Perception Surveys since 2012. The 2025 survey identified the drivers of trust from the perspective of key stakeholder groups across our supply chain, community, government and directly connected customer groups. Three strong trust drivers were identified:

- alignment with government energy policy
- helping stakeholders understand what Powerlink can and cannot control, and
- safety of operations.

While metrics for trust, reputation and engagement improved from 2024 to 2025, uncertainty among stakeholders heightens their expectations of Powerlink's performance. Stakeholders are looking to Powerlink for continuity and clear communication on the cost, constraints and deliverability of our services.

Survey results highlighted the need for Powerlink to demonstrate the value of network investment to underpin the safety, reliability and cost-efficiency of the transmission network. A summary of the research is published on our website[36].

[35] https://www.powerlink.com.au/engagement-forums
[36] https://www.powerlink.com.au/community/stakeholder-engagement/customer-research

3.6.5 Key research insights for our Revenue Proposal

Insights from end-user and stakeholder engagement reinforce Powerlink's view that the balance between cost, network reliability, resilience and safety remains important to our customers and other stakeholders.

There is broad support for network investment to secure longer-term benefits, and customers are seeking greater transparency on the cost and value of transmission developments. In response, we have increased focus on deliverability of future projects and initiatives Powerlink undertakes to deliver projects on-time and on-budget (refer Chapter 4 Capital Expenditure and Appendix 4.09 Deliverability Assessment).

Recognising that customers place a high value on price predictability, Powerlink suggested an alternative way to smooth the indicative price path in our draft 2027-32 Revenue Proposal (published in September 2025). This was intended to prevent sharp increases and drive stability. We empowered the RPRG to decide which approach should be included in our Revenue Proposal. The RPRG endorsed this method, and it now underpins our revenue forecast in the 2027-32 Revenue Proposal.

Further information on Powerlink's price path is included in Chapter 10 Maximum Allowed Revenue and Price Impact. At the specific request of the RPRG, we have also provided analysis in Appendix 10.01 of potential price impacts for customers in relation to capital and operating expenditure that are subject to alternative regulatory mechanisms. We consider this transparent approach to the total potential price impacts is essential to continuing to engage openly and honestly on this Revenue Proposal.

3.7 How feedback influenced our decision making

We have committed to genuinely considering input and feedback received, consistent with the areas of focus identified in the scope of our engagement on this 2027-32 Revenue Proposal (refer Section 3.3.1). A more detailed overview of the feedback received and how it influenced decision making is included as Appendix 3.03 Engagement Approach and Outcomes.

We sought feedback on our draft Revenue Proposal through various avenues. We provided an overview and a set of questions to guide feedback and an online form on our website for collecting anonymous submissions. We requested that submissions be provided four weeks after publication. The RPRG provided a detailed public submission which provided feedback on the guiding questions and identified areas for further engagement prior to lodgement of the Revenue Proposal, included as Appendix 3.04.

3.7.1 RPRG consideration of alternative proposed approaches

The direct influence of the RPRG is reflected throughout our Revenue Proposal and its constructive feedback has shaped our approach to testing, challenging and refining our forecasts, revenue and pricing outcomes. In particular, the RPRG guided our approach in respect of the following four key issues.

Price path smoothing

In response to clear customer feedback that price predictability is highly valued, Powerlink proposed an alternative approach to smoothing the indicative price path in our draft 2027-32 Revenue Proposal, to avoid sudden increases and provide greater price stability.

We empowered the RPRG to determine the approach to be included in our Revenue Proposal. The RPRG specifically supported this approach, and this now forms the basis of our revenue forecast in this 2027-32 Revenue Proposal.

CESS net carryover calculation

We proposed an alternative approach for calculating net carryovers under the Capital Expenditure Sharing Scheme (CESS) in our draft 2027-32 Revenue Proposal. The approach comprised restating the capital expenditure allowance for the 2022-27 regulatory period to assess performance under the CESS. The restated capital expenditure allowance included revised escalation for material changes to input costs that were outside Powerlink's control. This approach reduced Powerlink's forecast penalty under the CESS by an estimated $84 million for the 2022-27 regulatory period.

In its October 2025 submission, the RPRG commented that it did not support retrospective changes in methodology and noted that substantive changes to AER methodology should occur through a network-wide review rather than during an individual reset. As a result, we have adopted the AER's current approach to calculating CESS net carryovers in this Revenue Proposal.

Operating expenditure output growth trend

As detailed in our draft Revenue Proposal, Powerlink considers that an alternative output growth measure may be more appropriate to represent the increasing complexity experienced by Transmission Network Service Providers (TNSPs). Several alternatives were presented to the RPRG in November 2025 with a comparison to existing AER measures.

Powerlink empowered the RPRG to select the measure to be applied for Powerlink's 2027-32 operating expenditure forecast. While the RPRG acknowledged Powerlink's proposed measures had potential to better reflect the growing complexity facing TNSPs, it expressed a preference for an industry wide review of the output growth measurement methodology. The group considered this would provide for fuller exploration of different alternatives and their application across all network service providers.

Based on the RPRG decision, Powerlink has applied the AER's existing output growth measures to its operating expenditure forecast in this Revenue Proposal.

Demand Management Innovation Allowance Mechanism (DMIAM)

At its RPRG meeting in December 2025, Powerlink proposed to not seek a DMIAM allowance in its 2027-32 Revenue Proposal. After being provided further information on the demand management initiatives we had progressed in the normal course of business, the RPRG was asked to formally respond to confirm its position in respect to the DMIAM.

The RPRG wrote to Powerlink on 22 December 2025, supporting Powerlink's proposed approach. The reason provided by the RPRG was its confidence that:

- *demand management innovation is managed as part of business-as-usual work at Powerlink, and that this will continue to meet future demands for this type of investigation and research*
- *the Unlocking the Battery research is indicative of the leading approach taken by Powerlink and*
- *as in the past, Powerlink will continue to freely share information on its innovation programs.*

Based on the RPRG's feedback, Powerlink has not sought a DMIAM allowance in this Revenue Proposal.

3.7.2 Other engagement outcomes

In addition to the specific issues addressed by the RPRG, customer feedback has materially shaped other areas of our Revenue Proposal including impacts on our engagement approach, expenditure forecasts, revenue and pricing. Some of these impacts are described below, while all feedback received and how that feedback influenced our engagement and decision making is summarised in Appendix 3.03 Engagement Approach and Outcomes.

Engagement approach

- The capable of acceptance criteria and framework were developed collaboratively with the RPRG.
- In response to feedback to broaden its engagement, Powerlink included questions in the QHES and undertook dedicated engagement with directly connected and C&I customers, including an online survey.
- Established an independent Chair for customer representatives of the RPRG to coordinate its consideration and input.

Expenditure forecasts

- Six expenditure forecasts were presented in depth over the course of 11 months, illustrating how we were considering and responding to feedback provided.
- We provided a detailed explanation of our Expenditure Forecasting Methodology prior to its lodgement in June 2025, while additional engagement sessions were held to dive deeper on capital expenditure forecasting.
- Going beyond the usual level of detail, greater insight into our lessons learnt process and assessment of deliverability was provided in response to specific questions from the RPRG, with more information included with our Revenue Proposal (refer Appendix 4.09 Deliverability Assessment).

Revenue and pricing

- The RPRG advocated for customers to have transparency on the potential impacts of transmission investments that fall outside the scope of the revenue determination process. Powerlink has included an analysis in Appendix 10.01 of this Revenue Proposal.

3.8 Engagement evaluation

3.8.1 RPRG feedback

Powerlink asked the RPRG to provide feedback on its engagement throughout the development of its Revenue Proposal process, to ensure that our approach remained effective and responsive to customer concerns. We sought feedback in May and August 2025, to understand the effectiveness of the engagement undertaken to date, suitability of the supporting documents provided and additional engagement topics.

The RPRG confirmed that the engagement scope, frequency of meetings and composition of the group was effective. They also acknowledged that the information provided by Powerlink was clear, well understood and accessible to both RPRG members and their stakeholders.

At our Customer Panel meeting in September 2025, members reflected on the benefits of integrating revenue determination engagement with BAU activities for building capacity of members and ensuring knowledge retention for future determinations. The sharing of expertise by Powerlink and more experienced members of the RPRG was acknowledged for its role in enabling newer members to develop their understanding and capability.

The RPRG provided a formal Statement on Engagement in January 2026. An abridged version of the statement is included below:

> *Powerlink's Regulatory Proposal Reference Group consider that their involvement in development of Powerlink's 2027-32 Regulatory Proposal has been highly collaborative with Powerlink showing a genuine commitment to best practice engagement.*
>
> *The depth and breadth of engagement with the RPRG have been impressive … Powerlink has taken care to ensure that materials prepared for consideration by the RPRG and Customer Panel are clear and are presented in a way that is appropriate for a non-technical audience.*
>
> *We have sought and been provided with additional information as required and have been comfortable challenging Powerlink's position on many aspects of the proposal. Interactions with the RPRG have been adaptive and flexible, often driven by specific RPRG requests. Powerlink has been sincere in its engagement and has been open to receiving feedback (both positive and negative) from RPRG and responding to that feedback in a considered and informative way.*
>
> *Throughout the process of engagement on Powerlink's 2027-32 Regulatory Proposal our objective has been to scrutinise and interrogate the various elements of the Proposal to ensure that customer perspectives are recognised and are adequately reflected in the outcomes. To date, the RPRG is satisfied that the material that has been presented to us meets these objectives.*

The full RPRG Statement on Engagement is included as Appendix 3.06.

3.8.2 Engagement evaluation KPIs

Our Engagement Plan includes a set of Key Performance Indicators (KPIs), with a combination of qualitative and quantitative data to assess our performance.

All Customer Panel members were asked to assess our Revenue Proposal engagement as part of an annual evaluation survey, which included targeted questions for RPRG and non-RPRG members. The KPIs and evaluation outcomes for RPRG members are provided in Table 3.4.

A summary of the survey outcomes is provided in Appendix 3.05 Customer Panel Annual Evaluation Results.

Table 3.4 – RPRG engagement evaluation KPIs

KPI	Target	Measurement	Result[37]
Effectiveness and quality of information provided to stakeholders	Overall satisfaction rating of 70% for quality of information provided	The information provided to the RPRG is clear, concise, and of high quality.	100%
		I have been supported throughout the process to develop knowledge relevant to my role on the RPRG.	96%
Stakeholders were engaged at appropriate level on the IAP2 spectrum	Majority of stakeholders had appropriate level of influence on Powerlink decision making	I am satisfied that the process has allowed an appropriate influence on Powerlink decision making.	100%
		RPRG members have been engaged at an appropriate level.	100%

[37] Appendix 3.05 – Customer Panel Annual Evaluation Results

KPI	Target	Measurement	Result[37]
Satisfaction level of stakeholders with engagement activities	Overall satisfaction rating of 70% for engagement activities	I am satisfied with the length and frequency of meetings and the relevance of topics discussed.	95%
		I am satisfied with the overall management, coordination and outcomes of engagement activities.	100%
Impact of engagement on Powerlink decision making and quality of feedback provided	Ability to demonstrate what changed as a result of engagement	The RPRG were "satisfied that Powerlink had identified the impact of engagement" on the draft Revenue Proposal[38].	See Section 3.8.1
Timely delivery of engagement program	Engagement program delivered on-schedule	The RPRG met monthly between February and December 2025, consistent with the Engagement Plan[39] and Terms of Reference[40].	See Section 3.4

Table 3.5 summarises the evaluation outcomes of Customer Panel members who did not sit on the RPRG.

Table 3.5 – Customer Panel (non-RPRG) engagement evaluation KPIs

KPI	Target	Measurement	Result[41]
Effectiveness and quality of information provided to stakeholders	Overall satisfaction rating of 70% for quality of information provided	The information shared about the Revenue Proposal and consultation process was clear and easy to engage with.	90%
		The draft Revenue Proposal and supporting materials enabled me to provide informed input or make a submission.	80%
Stakeholders were engaged at appropriate level on the IAP2 spectrum	Majority of stakeholders had appropriate level of influence on Powerlink decision making	I feel confident that the process has been transparent and inclusive of customer perspectives.	73%
		I have a clear understanding of the Revenue Proposal development process and my role within it.	80%

[38] Appendix 3.04 – RPRG submission on our draft Revenue Proposal
[39] Appendix 3.01 – Revenue Proposal Engagement Plan
[40] Appendix 3.02 – RPRG Terms of Reference
[41] Appendix 3.05 – Customer Panel Annual Evaluation Results

3.8.2.1 Improvement opportunities

Based on feedback received, we identified the following areas for improvement in the next phase of the revenue determination process:

- continue to build Customer Panel confidence in the revenue determination engagement process, transparency and accountabilities
- extend timeframes for RPRG and Customer Panel to process and respond to key documents
- facilitate additional in-person engagement with existing customer cohorts to obtain broader feedback on key documents and decisions, and
- ease the burden for customers by amalgamating Revenue Proposal surveys with existing data collection conducted.

4 Capital Expenditure

4.1 Introduction

This chapter provides an overview of Powerlink's performance against the Australian Energy Regulator's (AER's) allowances for capital expenditure during the current 2022-27 and preceding 2017-22 regulatory period and outlines our forecast capital expenditure in the 2027-32 regulatory period[42].

Key highlights:

2022-27 regulatory period

- We forecast capital expenditure for the 2022-27 regulatory period of $1,504.5 million ($ real, 2026/27). This is $423.5 million (39%) higher than the AER's allowance of $1,081.0 million ($ real, 2026/27).
- We have exceeded our capital expenditure allowance in the capital expenditure ex post review period by 6.3%. Powerlink does not consider this a significant overspend within the context of the operating environment.

2027-32 regulatory period

- Our forecast capital expenditure for the 2027-32 regulatory period is $2,499.5 million ($ real, 2026/27) which is $995.0 million (66%) higher than actual/forecast capital expenditure for the 2022-27 regulatory period.
- The key drivers that underpin our forecast for the 2027-32 regulatory period are:
    - reinvestment in the transmission network to maintain the safety, security and reliability of supply as our assets continue to age
    - our response to the changing use of electricity and the impact on our transmission network
    - critical investment in the redevelopment of our Virginia complex and the development of a facility in Gladstone as we grow our regional workforce
    - investment in easements to support new load-driven connections and upgraded transmission infrastructure identified in the Queensland Government's Energy Roadmap 2025, and
    - investment in physical and cyber security to manage evolving threats to our infrastructure.
- The majority of our forecast capital expenditure is non load-driven network capital expenditure of $1,939.3 million ($ real, 2026/27).
- Our hybrid forecasting approach integrates top-down and bottom-up forecast methods, with project-specific justification provided for over 90% of our forecast capital expenditure.
- We have proposed nine contingent projects which will only be activated within-period subject to AER verification of pre-identified triggers, need and costs.
- We completed a deliverability assessment of the forecast capital expenditure which is provided in Appendix 4.09.

[42] The capital expenditure forecast in this chapter excludes expenditure associated with Priority Transmission Investment projects and contingent projects subject to a contingent project application in the current regulatory period, as these are subject to regulatory mechanisms outside the revenue determination process. The impact of these works on the deliverability of the capital expenditure forecast in this Revenue Proposal is considered in Appendix 4.09 Deliverability Assessment, while the potential pricing impact of these works are modelled in Appendix 10.01 Pricing Impact Scenarios.

4.2 Regulatory requirements

The National Electricity Rules (Rules)[43] require that our Revenue Proposal provides information on our capital expenditure for each year of the previous and current regulatory periods. The Rules[44] also require that the Australian Energy Regulator (AER) has regard to this expenditure when it considers our forecast capital expenditure.

Prior to the submission of our Revenue Proposal, we are required to propose a methodology for the development of our capital and operating expenditure forecasts[45] (included as Appendix 4.03). This methodology, and our forecasts, must also have regard to the AER's Expenditure Forecast Assessment Guideline for Electricity Transmission[46].

We must submit our forecast capital expenditure for the 2027-32 regulatory period based on the requirements set out in the Rules[47].

Specifically, the Rules require that we include a total forecast capital expenditure which achieves the *capital expenditure objectives*, reflects the *capital expenditure criteria* and has regard to the *capital expenditure factors*. In Section 4.3.1 we explain how our capital expenditure forecast achieves the *capital expenditure objectives* while we explain how our capital expenditure forecast reflects the *capital expenditure criteria* and has regard to the *capital expenditure factors* in Appendix 4.01.

4.3 Historical capital expenditure

This section summarises our historical capital expenditure, consistent with the requirements of the Rules[48].

4.3.1 Historical capital expenditure summary

Table 4.1 shows our capital expenditure for the previous 2017-22 and current 2022-27 regulatory periods by expenditure category. Expenditure for the 2018 to 2025 financial years is based on actual expenditure, while the 2026 and 2027 financial years are based on our current expenditure forecasts.

[43] National Electricity Rules, Schedule 6A.1, clause S6A.1.1.
[44] National Electricity Rules, clause 6A.6.7(e)(5).
[45] National Electricity Rules, clause 6A.10.1B.
[46] Expenditure Forecast Assessment Guideline for Electricity Transmission, Australian Energy Regulator, October 2024.
[47] National Electricity Rules, clause 6A.6.7.
[48] National Electricity Rules, Schedule 6A.1, clause S6A.1.1(6).

Table 4.1 - Capital expenditure - actual/forecast ($million real, 2026/27)

	2017-22 regulatory period						2022-27 regulatory period					
	2018	2019	2020	2021	2022	Total	2023	2024	2025	2026 forecast	2027 forecast	Total
Network load driven capital expenditure												
Augmentations	1.7	7.0	4.8	5.7	26.5	**45.7**	10.0	15.4	8.8	15.0	10.5	**59.6**
Connections	-	0.1	-	-	-	**0.1**	-	-	-	-	-	**-**
Easements	(0.2)	1.0	2.5	0.4	2.1	**5.9**	0.4	1.6	0.6	16.0	14.6	**33.2**
Total load-driven	**1.4**	**8.1**	**7.4**	**6.1**	**28.5**	**51.6**	**10.5**	**17.0**	**9.4**	**31.0**	**25.0**	**92.9**
Network non-load driven capital expenditure												
Reinvestments	150.8	180.7	170.0	171.2	168.4	**841.0**	185.2	195.4	151.8	261.1	295.2	**1,088.8**
System Services	-	-	-	-	-	**-**	6.1	2.2	7.7	0.1	-	**16.1**
Security/Compliance	25.7	2.7	1.6	13.5	2.6	**46.1**	8.9	9.0	5.8	14.8	17.4	**55.9**
Other	(0.3)	1.2	4.1	7.5	14.4	**26.8**	13.4	6.1	16.6	25.3	8.3	**69.7**
Total non-load driven	**176.1**	**184.6**	**175.8**	**192.1**	**185.4**	**913.9**	**213.7**	**212.7**	**181.9**	**301.3**	**320.9**	**1,230.5**
Total Network	**177.5**	**192.7**	**183.2**	**198.2**	**213.9**	**965.5**	**224.1**	**229.7**	**191.3**	**332.3**	**345.9**	**1,323.4**
Non-network capital expenditure												
Business IT	14.8	15.8	25.2	21.7	16.8	**94.4**	19.0	23.6	22.2	16.9	16.0	**97.7**
Support the Business	5.8	10.1	7.1	8.9	16.4	**48.2**	8.9	20.4	8.4	21.5	24.3	**83.4**
Total Non-network	**20.6**	**25.8**	**32.4**	**30.6**	**33.2**	**142.6**	**27.9**	**44.0**	**30.6**	**38.4**	**40.3**	**181.1**
TOTAL CAPITAL EXPENDITURE [1,2]	**198.1**	**218.5**	**215.5**	**228.8**	**247.1**	**1,108.1**	**252.0**	**273.7**	**221.9**	**370.7**	**386.2**	**1,504.5**

(1) All figures are net of disposals and reflect the recast numbers accounting for the adjustments made in FY2025.
(2) Actual/forecast expenditure reported above does not include any margins paid or expected to be paid to related parties.

4.3.2 Overall performance against allowance

In determining the Maximum Allowed Revenue (MAR) that Powerlink can recover during a regulatory period, the AER provides an allowance for the prudent and efficient capital expenditure needed to achieve the capital expenditure objectives.

For our current 2022-27 regulatory period, this was based on Powerlink's forecast in January 2021. In its September 2021 Draft Decision, the AER determined Powerlink's Revenue Proposal was capable of acceptance in all material respects. As a result, we did not re-forecast our capital expenditure, apart from applying an administrative update to reflect the latest inflation figures.

We did not apply a cost estimation risk factor, and we did not anticipate the significant global factors that have subsequently impacted the cost of transmission works. The AER's original allowance for the 2022-27 regulatory period was $1,081.0 million, restated in real 2026/27 prices.

At this time, we forecast our total capital expenditure for the 2022-27 regulatory period to be $423.5 million (39%) more than the AER's restated capital expenditure allowance. Table 4.2 summarises our total capital expenditure compared to the AER's allowance for the current 2022-27 regulatory period[49]. Expenditure for the 2026 to 2027 financial years is based on our current forecast.

Table 4.2 - Capital expenditure - allowance vs actual/forecast ($million real, 2026/27)

	2023	2024	2025	2026 forecast	2027 forecast	Total
AER Allowance	237.8	261.9	197.2	191.0	193.1	**1,081.0**
Actual/forecast	252.0	273.7	221.9	370.7	386.2	**1,504.5**
Difference	14.2	11.7	24.8	179.6	193.2	**423.5**
Difference (%)	6%	4%	13%	94%	100%	**39%**

Powerlink considers the additional capital expenditure within the 2022-27 regulatory period was necessary to continue to provide safe and reliable prescribed transmission services. As described in Chapter 2 Operating Environment, the current 2022-27 regulatory period has been challenging for all network businesses in Australia and abroad due primarily to global events, outside of individual businesses' control.

We understand the long-term impact on customer bills arising from additional capital expenditure, as well as the financial penalties to Powerlink. We have proactively sought to address the inflationary pressures where possible, and actively deferred work where it has been safe and efficient to do so. This has involved application of the outcomes of our Asset Reinvestment Review[50] to transmission line refit works, and accepting slightly higher risks to reduce secondary systems replacement needs within the current period.

We are continuing to test and challenge the need, timing and deliverability of our capital works in the normal course of business in an effort to reduce cost impacts to customers.

[49] Final Decision Powerlink Queensland Transmission Determination 2022 to 2027, Australian Energy Regulator, April 2022, page 45.
[50] Asset Reinvestment Review Working Group Report, Powerlink, June 2023.

4.3.3 Category specific performance against AER allowance

This section compares the actual/forecast capital expenditure to the AER allowance by category.

Under the regulatory framework, the AER's capital expenditure allowance is provided as a single, aggregate funding envelope rather than project-specific allocations. Powerlink is responsible for managing and deploying the allowance in a prudent and efficient manner within the regulatory period.

Table 4.3 - Capital expenditure - allowance vs actual/forecast ($million real, 2026/27)

	AER Allowance 2022-27	Actual/forecast 2022-27	Variance
Network load driven capital expenditure			
Augmentations	8.2	59.6	51.4
Connections	2.9	-	(2.8)
Easements	26.4	33.2	6.8
Total load driven	**37.5**	**92.9**	**55.4**
Network non-load driven capital expenditure			
Reinvestments	843.6	1,088.8	245.2
System Services	28.2	16.1	(12.1)
Security/Compliance	18.1	55.9	37.8
Other	18.0	69.7	51.7
Total non-load driven	**908.0**	**1,230.5**	**322.6**
Total Network	**945.5**	**1,323.4**	**377.9**
Non-network capital expenditure			
Business IT	74.4	97.7	23.3
Support the Business	61.1	83.4	22.3
Total Non-network	**135.5**	**181.1**	**45.6**
TOTAL CAPITAL EXPENDITURE	**1,081.0**	**1,504.5**	**423.5**

4.3.3.1 Network load driven capital expenditure

We forecast our load-driven capital expenditure for the 2022-27 regulatory period will be $55.4 million higher than the AER's allowance.

The main driver of the additional expenditure is augmentations, comprising targeted works on selected transmission lines within a defined geographic program to address specific area-based reliability requirements. These works increase the capability of the transmission network by increasing the rating of existing overhead transmission lines without the need to rebuild or establish additional lines. This is achieved by improving physical clearances to the transmission lines.

An increased volume of these works was undertaken to address emerging power transfer limitations in the period. The cost of the works also significantly increased due to inflationary pressures and additional project scope, as the specific activity to address the limitation was developed after detailed design was completed.

The underspend in connections relates to the deferral of one project, at Goodna Substation, included in the allowance for the current period. We are continuing to evaluate the need timing as part of joint planning with Energy Queensland, considering a special protection scheme and load transfers to defer the project further. This project is not included in our forecast for the 2027-32 regulatory period.

Expenditure on easements is forecast to be $6.8 million higher than the AER's allowance for the regulatory period. This is primarily due to easements for a new transmission line route between Woree and Kamerunga substations to support ongoing reliability of supply in the area.

4.3.3.2 Network non-load driven capital expenditure

We currently forecast that we will invest $322.6 million more than the AER's allowance for network non-load driven capital expenditure.

Reinvestments

We expect a total reinvestment expenditure of $1,088.8 million in the 2022-27 regulatory period, which is $245.2 million higher than the AER's allowance. The additional reinvestment expenditure is primarily due to the increased cost of our Next Generation Network Operations (NGNO) program to replace our Energy Management System (EMS) and associated infrastructure and systems.

Our network operations are central to navigating the challenges of the energy transition, and core to this is our EMS. The EMS provides visibility and situational awareness of an increasingly complex power system and is crucial to maintain a safe and reliable electricity supply. Our current EMS has reached end-of-life, exceeding its original design life and extended vendor support period, and is therefore being replaced. When we submitted our previous Revenue Proposal in January 2021, we expected this replacement to be largely completed within the 2017-22 regulatory period with final testing and commissioning to occur early in the current regulatory period. As the AER accepted all key elements of the Revenue Proposal in its Draft Decision (September 2021), no further material amendments were put forward in our revised Revenue Proposal submitted in November 2021.

However, delivery of the project was constrained significantly by the long-tail impacts of COVID-19, which was not apparent at the time, while subsequent detailed design identified much greater complexity in the architecture and interoperability with other systems. Over the life of the EMS, Powerlink implemented unique customisations to the existing EMS to extend its life and ability to support the energy transition for the benefit of customers. However, this has created additional challenges in moving to a new, contemporary system. Consequently, we had underestimated the true cost to replace the EMS and the scale of the supporting works necessary. The increased complexity of replacing this system, combined with the industry-specific inflationary pressures discussed in Chapter 2 Operating Environment, has resulted in an additional $206.3 million network reinvestment capital expenditure on NGNO related projects within the current 2022-27 regulatory period.

We also increased reinvestment capital expenditure on substation primary plant. A key driver of this increased expenditure is the need to replace 430 oil-filled current transformers at 23 substation sites due to significant safety concerns. This safety risk was unforeseen, as the age of these current transformers is approximately half of their original expected design life. The current transformer replacement program has further impacted the delivery of the portfolio of works due to the need to restrict access to substations with these specific current transformers or, where necessary, implement additional safeguards to gain access to the substations. Prioritisation of the unforeseen primary plant reinvestment, and the consequential resource and safe-access impacts, also resulted in lower than planned expenditure on secondary systems replacements.

Both substation primary and secondary reinvestment have also been impacted by the significant cost increases arising from industry-specific inflationary pressures. We reduced expenditure on transmission line reinvestment as we implemented the findings of our Asset Reinvestment Review[51].

This enabled us to efficiently defer expenditure by prioritising works, balancing reduced expenditure against incremental network risk. As part of this review, we committed to return any windfall gains made under the Capital Expenditure Sharing Scheme (CESS). However, increased costs and complexity in the delivery of transmission works mean that there is no windfall gain. The approach has however allowed us to prioritise capital expenditure within the period to mitigate the overall increase in capital expenditure.

System Services

We currently forecast that we will invest $12.1 million less than the AER's allowance for system services. This underspend relates to the use of a more efficient non-network alternative for the provision of voltage support services in South-East Queensland.

In October 2021, the Australian Energy Market Commission (AEMC) introduced the Efficient Management of System Strength on the Power System Rule change. From December 2025, Powerlink as the System Strength Service Provider in Queensland is required to plan, procure and make available system strength services. Consequently, Powerlink completed a Regulatory Investment Test for Transmission (RIT-T) for System Strength in July 2025[52], recommending investment in up to nine synchronous condensers across Central and Southern Queensland by June 2034.

The 2021 Rule change contains a transitional provision, allowing Powerlink to make a contingent project application (CPA) to the AER requesting an amended revenue determination for the current regulatory period, incorporating the capital and operating expenditure arising from the preferred option identified in the RIT-T. The system services actual and forecast capital expenditure in this Revenue Proposal does not include investment in synchronous condensers to address system strength requirements. These will be treated as part of Powerlink's CPA to be submitted in accordance with the Rules[53] in the current regulatory period.

Security and Compliance

Powerlink has exceeded the AER allowance in this category by $37.8 million, driven largely by two key requirements.

Security investments arising from Powerlink's obligations as a responsible entity under the *Security of Critical Infrastructure Act 2018* (SOCI) and a step change in cyber security requirements have been a major factor. Security threats for the energy sector have escalated rapidly and significantly in recent years. These threats required substantial additional investment to improve operational technology (OT) cyber security and physical security of operational sites, resulting in a total of $16.3 million of investments in both physical and cyber security in the current period.

Increasing system complexity driven by the rapid shift in the mix of generation connected to the transmission network together with the significant change in the network demand, both in scale and usage, has altered the

[51] Asset Reinvestment Review Working Group Report, Powerlink, June 2023.
[52] Addressing System Strength Requirements in Queensland from December 2025 – Project Assessment Conclusions Report, Powerlink, June 2025.
[53] National Electricity Rules, Schedule 6A.8 clause 6A.8.2

performance characteristics of the transmission network. These changes have required Powerlink to develop and implement new control and protection schemes to maintain system stability in accordance with the Rules[54].

Wide Area Monitoring Protection and Control (WAMPAC) is a new secondary system platform that Powerlink has implemented, which rapidly detects specified conditions on the grid and coordinates appropriate responses across the state-wide network. This approach avoids the need for more expensive network augmentation and flow-on cost impacts to customers. In the current period we forecast capital expenditure of $11.7 million on several WAMPAC schemes across the state to drive further value for our customers.

Other

We currently forecast that we will overspend the AER allowance in this category by $51.7 million.

In June 2022, AEMO identified critical locations in the Queensland network where high-speed streaming of power system data is required. AEMO issued a notice under the Rules, which requires Powerlink to install and configure phasor measurement units (PMUs) at 23 locations[55]. In the current period we forecast $16.6 million will be invested on installation of PMUs that was not included in capital expenditure allowance for the current regulatory period.

The majority of the balance of the expenditure in this category is due to a major investment to establish a new Business Continuity Site (BCS) to meet evolving cyber and physical security requirements. This included the necessary infrastructure to support the new AEMS at the BCS. Additionally, we have also enhanced field delivery technologies within the current regulatory period.

4.3.3.3 Non-network capital expenditure

Our current forecast is that we will invest $45.6 million more than the AER's allowance for non-network capital expenditure in the 2022-27 regulatory period.

Business Information Technology (IT)

Additional investment in cyber security was necessary to meet Australian Energy Sector Cyber Security Framework (AESCSF) standards as well as expenditure on specific cyber risk mitigation. These additional requirements, in addition to cost escalation for IT services, equipment and software, means that we currently forecast capital expenditure of $23.3 million over the AER allowance.

Support the Business

We have spent an additional $22.3 million compared to the AER allowance in the Support the Business category. The principal drivers for this overspend were fleet, at $16.1 million, and tools and equipment, at $7.9 million.

The additional fleet expenditure is due to a targeted approach to enhance Powerlink's operational capability in the Gladstone and Townsville regions. Previously, short-term rentals and leases had been utilised to support project and maintenance work in these regions. With the expansion of Powerlink's regional presence in both Gladstone and Townville, a more efficient approach in the long-term was to purchase vehicles for those resources based in these regions.

Similar to fleet, the additional tools and equipment expenditure is primarily due to the expansion of Powerlink's regional presence, and the need to fit-out vehicles and supply technicians with the required tools and equipment for constructing and maintaining critical network assets.

[54] National Electricity Rules, Schedule 5.1, clause S5.1.8.
[55] Notice issued by AEMO to Powerlink on 27 June 2022 under clauses 4.11.1(d) and (e) of the National Electricity Rules.

4.3.4 Projects deferred from current period into next period

As part of ongoing project monitoring, certain projects identified in the 2023-27 Revenue Proposal were not commenced in the current period and are proposed for inclusion in the 2027-32 regulatory period.

Table 4.4 includes a list of projects deferred from the current regulatory period, and the rationale for their deferral, in line with the requirements of the Reset RIN.

Table 4.4 - Projects deferred from current regulatory period to next

Project	Rationale for Deferral
Molendinar Secondary System Replacement	Reprioritisation of capital program taking into account deliverability and acceptance of a slightly greater level of risk
Murarrie Secondary System Replacement	
Middle Ridge Secondary System Replacement	
Goodna Secondary System Replacement	
Calvale Primary Plant Replacement	Reprioritisation of capital program taking into account deliverability and acceptance of a slightly greater level of risk
South Pine Transformer Replacement	
Tully Transformer Replacement	
Ross to Chalumbin Transmission Line Refit	Project deferred arising from implementation of the Asset Reinvestment Review
Telecoms Network Consolidation Stage 3	Strategy for these projects has not materially changed but implementation of the first stage encountered technology challenges which has delayed the subsequent stages
Telecoms Network Consolidation Stage 4	
OpsWAN Replacement Stage 3	
OpsWAN Replacement Stage 4	

4.3.5 Ex post review period

The AER may undertake a review of past capital expenditure where the capital expenditure within a defined review period exceeds the AER's respective capital expenditure allowance[56]. The purpose of the review is to assess any capital expenditure over the allowance and exclude any additional capital expenditure that is not deemed prudent and efficient from being included in the Regulatory Asset Base (RAB). The AER describes the ex post review process in its Capital Expenditure Incentive Guideline[57].

[56] National Electricity Rules, Schedule 6A.2, clause S6A.2.2A.
[57] Capital Expenditure Incentive Guideline for Electricity Network Service Providers, Australian Energy Regulator, August 2025, pages 18-21.

For Powerlink's 2027-32 revenue determination, the review period is from 1 July 2020 to 30 June 2025. Our capital expenditure within the review period compared to the AER allowance is shown in Table 4.5.

Table 4.5 - Capital Expenditure – ex post review period ($million, nominal)

	2021	2022	2023	2024	2025	Total
AER Allowance	185.5	179.7	209.3	239.9	184.9	**999.4**
Actual	180.5	201.7	221.8	250.6	208.2	**1,062.8**
Difference	(5.1)	22.0	12.5	10.7	23.2	**63.4**
Difference (%)	(3%)	12%	6%	4%	13%	**6.3%**

During the period from 2021, like all other network businesses in Australia, Powerlink experienced unprecedented increases in the costs of major plant items, materials and skilled resources (refer Chapter 2 Operating Environment). This led to increases in capital expenditure that were well outside our control.

Nevertheless, we have actively managed our capital expenditure and proactively sought to address these inflationary pressures where possible, and deferred work where it has been safe and efficient to do so. This has included application of the outcomes of our Asset Reinvestment Review to transmission line refit works and accepting slightly higher risks to reduce secondary systems replacement needs within the current period.

These actions resulted in an overspend in the review period of 6.3%. Powerlink does not consider this a significant overspend within the context of the operating environment.

4.4 Forecast capital expenditure

Our total forecast capital expenditure is $2,499.5 million ($ real, 2026/27). The majority of this is non-load driven network expenditure of $1,939.3 million to replace ageing or obsolete assets.

Our forecast expenditure by category is shown in Table 4.6.

Table 4.6 - Forecast capital expenditure by category ($million real, 2026/27)

Category	2028	2029	2030	2031	2032	Total
Network load driven capital expenditure						
Augmentations	5.8	-	-	-	-	**5.8**
Connections	-	-	-	-	-	**-**
Easements	26.5	40.9	56.3	83.8	87.5	**295.1**
Total Network – load-driven	**32.3**	**40.9**	**56.3**	**83.8**	**87.5**	**300.9**
Network non-load driven capital expenditure						
Reinvestments	394.5	315.1	259.8	367.2	337.6	**1,674.3**
System Services	-	-	-	-	-	**-**
Security/Compliance	13.4	22.3	34.6	47.8	48.7	**166.8**
Other	11.2	27.3	20.9	16.7	22.1	**98.3**
Total Network – non-load driven	**419.2**	**364.8**	**315.3**	**431.7**	**408.5**	**1,939.3**
Total Network	**451.5**	**405.7**	**371.6**	**515.5**	**496.0**	**2,240.2**
Non-network capital expenditure						
Business IT	4.9	5.9	6.4	5.3	4.9	**27.4**
Support the Business	59.9	92.0	50.3	14.6	15.1	**231.9**
Total Non-network	**64.8**	**97.9**	**56.7**	**19.9**	**20.0**	**259.2**
TOTAL CAPITAL EXPENDITURE	**516.3**	**503.5**	**428.3**	**535.4**	**516.0**	**2,499.5**

4.4.1 Capital expenditure objectives

We consider that our forecast capital expenditure achieves the capital expenditure objectives set out in clause 6A.6.7(a) of the Rules. This is summarised in Table 4.7 and discussed in detail in Appendix 4.01 Operating and Capital Expenditure Criteria and Factors.

Table 4.7 - How we meet the capital objectives

Capital expenditure objective	How our proposal meets this objective
Meet or manage the expected demand for prescribed transmission services over the period	Demand from our 2025 Transmission Annual Planning Report (TAPR) forecast shows steady average annual growth over the forecast horizon. The main driver for this is the magnitude and pace of electrification. In addition to meeting customer demand, Powerlink must also meet forecast increase in the demand for prescribed system services such as inertia and system strength, as set out in the Australian Energy Market Operator's (AEMO) 2025 Transition Plan for System Security[58].

[58] 2025 Transition Plan for System Security, Australian Energy Market Operator, December 2025.

Capital expenditure objective	How our proposal meets this objective
Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services	We are subject to regulatory obligations as the holder of a Transmission Authority under the *Electricity Act 1994 (Qld)* and as a registered Transmission Network Service Provider (TNSP) in the National Electricity Market (NEM). As a corporation, we are also subject to various environmental, cultural heritage, planning, industrial, Workplace Health & Safety, security of critical infrastructure, industrial, financial and other regulations. Our compliance with these regulatory obligations and requirements is encompassed in our Strategic Asset Management Plan, policies and procedures, which provide the foundation for our capital expenditure activities and is provided as supporting information with our Revenue Proposal.
Maintain the quality, reliability and security of supply of prescribed transmission services and maintain the safety, reliability and security of the transmission system through the supply of prescribed transmission services	Our capital expenditure forecasts include prudent provision to maintain the safety, reliability and security of the transmission system and deliver mandated quality, reliability and security of supply to our customers. An appropriate balance of operating and capital expenditure has been proposed within our 2027-32 Revenue Proposal to ensure network assets deliver the required quality, reliability, and security of supply in the most prudent and efficient manner.
Contribute to achieving emissions reduction targets through the supply of prescribed transmission services	Powerlink plays a pivotal role in Queensland's energy transition through its transmission infrastructure. As Queensland's System Strength Service Provider, Powerlink is investigating network and non-network solutions for provision of system strength services. Powerlink's investment in the transmission network ensures the continued provision of prescribed services necessary to support the connection of new generation. Contingent projects proposed in Section 4.5 support connection of new generation, electrification of existing load and provision of system strength services all of which may contribute to achieving emissions reduction in the 2027-32 regulatory period.

4.4.2 Changes from draft Revenue Proposal

Our draft Revenue Proposal included total forecast capital expenditure of $2,796.7 million ($ real, 2026/27). Since publishing our draft Revenue Proposal in September 2025, we have made several changes that in aggregate reduced our overall capital expenditure forecast by $297.2 million ($ real, 2026/27) and also resulted in changed totals at a category level.

These changes arose from engagement with the Revenue Proposal Reference Group (RPRG), and our ongoing test and challenge internally of the needs and a deliverability assessment resulting in:

- removal of synchronous condenser expenditure from the System Services category as this expenditure will be assessed by the AER as part of a contingent project application which we intend to lodge during 2026
- changes to total Reinvestment capital expenditure and the spend profile, arising from continued review of needs and deliverability and finalisation of detailed estimates
- reclassification of security program as Security/Compliance from Reinvestment
- increasing spend in Easements, primarily to progress acquisition to support new load driven connections to Energy Queensland, forecast to occur in the 2032-37 period and to support the future development of the transmission network described in the Queensland Energy Roadmap, and

- scope and timing of investment in the Virginia complex have been modified and we have included an asset transfer in relation to this project (refer Section 7.6) in the closing RAB at 30 June 2027, reducing the overall capital expenditure in the Support the Business category in the 2027-32 regulatory period.

Table 4.8 summarises the difference in total forecast capital expenditure between our draft Revenue Proposal and our Revenue Proposal.

Table 4.8 - Forecast capital expenditure comparison ($million real, 2026/27)

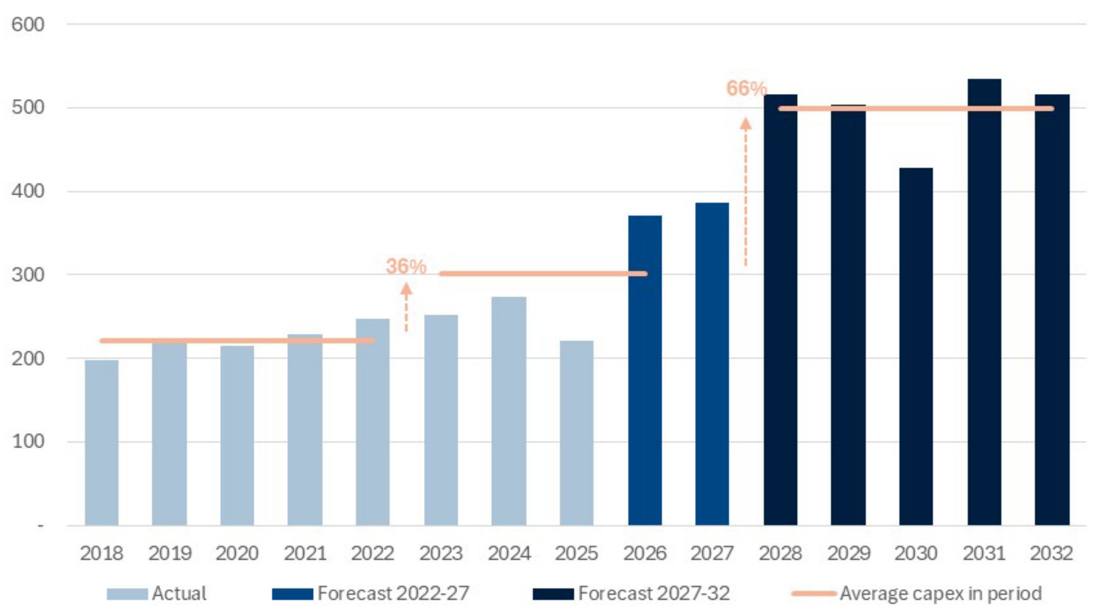
	2028	2029	2030	2031	2032	Total
Draft Revenue Proposal	795.3	619.1	589.6	483.3	324.4	**2,796.7**
Revenue Proposal	516.3	503.5	428.3	535.4	516.0	**2,499.5**
Difference	(279.0)	(115.6)	(161.3)	67.0	191.6	**(297.2)**
Difference (%)	(35%)	(19%)	(27%)	14%	59%	**(11%)**

4.4.3 Overview of forecast capital expenditure by category

Our forecast capital expenditure of $2,499.5 million for the 2027-32 regulatory period is $995.0 million higher than the actual/forecast expenditure in the current regulatory period. The capital expenditure forecast reflects the significant increase in the cost of major plant items and skilled resources that we experienced during the 2022-27 regulatory period.

Our 2027-32 forecast capital expenditure is compared to the current (2022-27) and previous (2017-22) regulatory periods in Figure 4.1.

Figure 4.1 - Capital expenditure ($million real, 2026/27)



A comparison by category of our forecast capital expenditure for the 2027-32 regulatory period with the actual/forecast capital expenditure in the current regulatory period is shown in Table 4.9.

Table 4.9 - Capital expenditure - comparison of 2027-32 forecast to 2022-27 actual/forecast ($million real, 2026/27)

	Actual/Forecast 2022-27	Forecast 2027-32	Variance
Network load driven capital expenditure			
Augmentations	59.6	5.8	(53.8)
Connections	-	-	-
Easements	33.2	295.1	261.9
Total load driven	**92.9**	**300.9**	**208.0**
Network non-load driven capital expenditure			
Reinvestments	1,088.8	1,674.3	585.4
System Services	16.1	-	(16.1)
Security/Compliance	55.9	166.8	110.9
Other	69.7	98.3	28.6
Total non-load driven	**1,230.5**	**1,939.3**	**708.8**
Total Network	**1,323.4**	**2,240.2**	**916.9**
Non-network capital expenditure			
Business IT	97.7	27.4	(70.3)
Support the Business	83.4	231.9	148.4
Total Non-network	**181.1**	**259.2**	**78.1**
TOTAL CAPITAL EXPENDITURE	**1,504.5**	**2,499.5**	**995.0**

4.4.3.1 Network load driven capital expenditure

Our total forecast load-driven expenditure of $300.9 million, which is $208.0 million higher than the actual/forecast expenditure in the current regulatory period.

There is a reduction in the regulated capital expenditure on load driven augmentations and an increase in easements expenditure. The reduction in augmentation related capital expenditure is due to the substantial augmentation capital expenditure being progressed under the Priority Transmission Investment (PTI) framework.

The significant investment in easements capital expenditure for the 2027-32 period is necessary to support the construction of new load driven connections to Energy Queensland and rebuild several transmission lines in the North Queensland and Gladstone regions, forecast to be required in the 2032-37 regulatory period. The forecast of $295.1 million for easements reflects a fundamental shift in the scale and complexity of future transmission development in Queensland, driven by changes to State and national policy, legislative frameworks, stakeholder expectations and benefits, and regulatory requirements.

The combined effect of these changes is that securing easements requires much longer lead times, greater levels of technical assessment, higher community and Traditional Owner involvement and a more resource intensive engagement program. Commencing easement activities during the 2027-32 regulatory period is a prudent and efficient way of ensuring Powerlink can meet the State's energy objectives, provide greater delivery certainty for future projects and comply with our regulatory obligations.

4.4.3.2 Network non-load driven capital expenditure

Non-load driven expenditure is the most significant contributor to our forecast capital expenditure for the 2027-32 regulatory period. Our forecast expenditure of $1,939.3 million is $708.8 million higher than the actual/forecast expenditure in the current regulatory period.

Most of the expenditure is in the reinvestments category. A large amount of this investment (approximately $370.7 million) relates to several large projects/programs of work, namely the substation and transmission line reinvestment at Kamerunga, and the physical security uplift program. Other non-load driven expenditure continues to follow the historical trend, once adjusted for the industry-specific inflation highlighted in Chapter 2 Operating Environment.

Reinvestments – transmission line refit

During the revenue determination process for our 2022-27 regulatory period, we committed to undertake a review of our approach to network asset reinvestment, particularly for overhead transmission lines. This review included representatives of customers, the AER and Powerlink subject matter experts, and concluded in June 2023 with the publication of the Asset Reinvestment Review Working Group Report[59]. The Asset Reinvestment Review concluded that Powerlink should:

- retain its existing definition of transmission line assets
- limit compliance upgrades to only those structures already undergoing condition-based works, and
- evaluate both single-stage and bundled multi-stage reinvestment options since no single approach is optimal in all circumstances.

These recommendations aim to deliver more targeted, risk-based and cost-effective reinvestment decisions aligned with network need and RIT-T principles. In preparing our 2027-32 Revenue Proposal we have implemented the key recommendations of the Asset Reinvestment Review. In addition, we identified further improvements to deliver a more cost-effective approach, which has substantially reduced the number of towers requiring intervention in the 2027-32 regulatory period.

Reinvestments – secondary systems and telecommunications

A significant driver of asset reinvestment expenditure is the need to renew our fleet of digital secondary systems and telecommunications assets. Our total forecast secondary systems capital expenditure of $534.9 million is $299.4 million more than the actual/forecast expenditure for the current regulatory period.

The nature of these digital technologies is such that obsolescence and lack of vendor support for discontinued devices are the primary drivers for reinvestment. Once a device is no longer available, its replacement is operationally and technically more complex due to issues such as:

- interoperability and protocol difference between other devices on site, and at adjacent substations
- the need to develop and test new configurations and settings
- physical differences with the mounting and installation, including cabling and connectivity, and
- legislative requirements for professional engineering certification[60].

[59] Asset Reinvestment Review Working Group Report, Powerlink, June 2023.
[60] *Professional Engineers Act 2002 (Qld),* section 115.

In the event of failure of an unsupported device, the return to service time increases considerably. In addition to the impacts of obsolescence at any one site, it is also important to note the compounding impact of equipment obsolescence that may occur across the fleet of secondary systems assets installed in the network. When a particular equipment type or model is no longer supported by the manufacturer, and limited spares are available to service the fleet of assets, an attempt to run multiple secondary systems to failure across the network would increase the likelihood of concurrent systemic faults. This would likely overwhelm our capacity to undertake corrective maintenance or replacement projects and potentially leave us in breach of the Rules[61], AEMO standards[62] and our jurisdictional obligations[63]. A coordinated and timely replacement program is essential to manage this risk.

In addition, the growing cyber threat landscape affecting the electricity sector means the timely deployment of software updates has become a critical component of maintaining appropriate cyber security standards. Sustained vendor support to ensure the availability and integrity of these updates is essential to safeguarding operational systems and meeting regulatory expectations for cyber resilience. For these reasons, it is critical to address the fleet of assets, such that the number of obsolete and unsupported devices in service on the network is managed effectively.

The typical product lifespan for our secondary systems assets is around 20 years. The expansion of our network during the 2000s and early 2010s in response to growth in customer demand means there is a greater volume of secondary systems assets requiring reinvestment in the 2027-32 regulatory period. This volume will continue to increase in subsequent regulatory periods and as such it is essential that the projects proposed for the 2027-32 regulatory period progress as planned to avoid the potential consequences of multiple secondary systems exceeding their useful life.

To address the challenges of managing an ageing fleet of assets, we have commenced a trial of in-situ replacement of secondary systems panels. This approach is enabled by the generation of digital secondary systems requiring replacement. We expect this trial to result in reduced costs, support shorter network outage times and enhance our capability in replacement techniques. This replacement approach comes with a trade-off of placing more pressure on scarce highly skilled resources necessary to undertake the work. The outcome of the trial will inform our approach to secondary systems reinvestment projects.

There have been rapid changes in the technology of telecommunications equipment, which enables the control and operation of the high voltage network. As telecommunications service providers look to remain competitive through adoption of new technologies to provide more features, the investment in legacy technology is reduced, resulting in shorter product support periods. This rapidly advancing environment is a key driver behind increased investment in telecommunications in the 2027-32 regulatory period.

Security and Compliance

Our total forecast Security and Compliance capital expenditure is $166.8 million. This is $110.9 million higher than the actual/forecast expenditure in the current regulatory period.

As part of our security strategy to protect business-critical assets, we have developed an investment case for future physical security uplift of our operational sites. This is currently based on a standardised approach to each site, based on its comparative size and criticality. A targeted risk assessment will be conducted to confirm the criticality and vulnerability of each site and works tailored to specific site requirements. This process will ensure

[61] National Electricity Rules, Schedule 5.1, clause S5.1.2.1(d), clause S5.1.9(c).
[62] Power System Operating Procedure (SO_OP_3715), AEMO and Power System Security Guidelines, AEMO.
[63] *Electricity Act 1994 (Qld),* section 34(1)(a) and Powerlink's Transmission Authority T01/98.

that implemented security controls are proportionate, effective, and aligned with our obligations under the *Security of Critical Infrastructure (SOCI) Act 2018*. This requirement will drive significant capital expenditure where existing security systems are replaced and enhanced in the 2027-32 regulatory period improving the physical security of existing operational sites.

Other

Our total forecast Other capital expenditure of $98.3 million is $28.6 million higher than the actual/forecast expenditure for the current regulatory period. This is predominantly driven by the Future Grid Operational Technology program, for which we have provided an investment case.

The increasing number of new generation and storage resources being integrated into the Queensland network is changing the behaviour of the power system. Combined with the challenging transmission network investment conditions and unbundling of system services (system strength, inertia, etc.), this results in greater variability and complexity for power system operators. In this evolving environment, there is a clear and urgent need to strengthen real time situational awareness and decision making to ensure operators can effectively monitor the network and respond swiftly to contingency events.

Additionally, the changing system dynamics are making network outage planning increasingly complex. To address these challenges, Powerlink is initiating a series of targeted work packages aimed at enhancing control room operations. These include improvements in forecasting and data analytics to leverage the NGNO program and support operational decisions, advanced tools for situational awareness, and operational capability to support the deployment of WAMPAC systems.

Collectively, these initiatives are designed not only to support more informed and agile operational responses but also to enable Powerlink to operate the network at higher risk tolerances. This will lead to improved network utilisation and reduced curtailment of generation, achieving system security and reliability outcomes at a lower cost to customers.

4.4.3.3 Non-network expenditure

Our total forecast non-network capital expenditure of $259.2 million is $78.1 million greater than the actual/ forecast expenditure for the current regulatory period.

The largest component of this expenditure relates to the need to substantially redevelop our Virginia complex to continue to efficiently provide prescribed transmission services. As highlighted in our 2023-27 Revenue Proposal it remains important that we provide facilities for contemporary work practices. Due to aged facilities, organisational growth, and the requirement to provide new and extended operational services, the Virginia complex will no longer be able to efficiently meet our business needs.

Further analysis of options during the current regulatory period has identified that it is not efficient to continue to reinvest in our existing facilities where the underlying infrastructure is over 60 years old. Consequently, we propose a more substantial investment in our Virginia complex as the most efficient solution to meet our long-term needs.

We extended our regional presence in Gladstone, to more efficiently provide support to the critical works to maintain safe, reliable and cost-effective supply in Central Queensland. While we achieved this in the current period with the establishment of an interim resource hub in Gladstone, we propose investment in a new facility in Gladstone. This is necessary to meet future regulatory, operational and system security obligations by enhancing local workforce capacity, reducing emergency and fault response times and improving deployment efficiency.

Our Business IT capital expenditure forecast for the 2027-32 period is $27.4 million. This is $70.3 million less than the actual/forecast expenditure for the current regulatory period. The decrease is due to the increased adoption of cloud-based services (or Software-as-a-Service). In April 2021, the International Accounting Standards Board clarified its definition of intangible assets which led to most Software-as-a-Service (SaaS) costs no longer meeting that definition. The International Financial Reporting Standards guidance suggested that these costs should be expensed (operating expenditure) rather than capitalised (capital expenditure), shifting the approach taken in the past in relation to cloud-based solutions.

Given the continuing maturity of SaaS offerings by leading technology companies, and the move by those companies to only offer SaaS solutions in the future, Powerlink has determined, in line with the Australian Accounting Standards, that most of the future IT investment will need to be treated as an operating expense rather than a capital asset.

4.5 Contingent projects

Contingent projects are investments that may be needed during the regulatory period should certain trigger events occur. As the need for investment during the regulatory period is not certain, or the costs associated with addressing the need for investment are not sufficiently certain, contingent projects do not form part of the ex-ante capital expenditure allowance[64]. If a contingent project trigger event occurs during the regulatory period, we can apply to the AER to amend the Revenue Determination to include the revenue required to undertake the contingent project. Before it amends the Revenue Determination the AER will assess the prudency and efficiency of the proposed additional expenditure[65].

Generally, contingent projects are significant network augmentation projects that are reasonably required to achieve the capital expenditure objectives set out in the Rules. Such projects are often linked to unique investment drivers, such as commitment of new large loads or retirement of generation, rather than general investment drivers such as expectations of load growth in a region.

We have considered potential contingent projects under two categories of drivers.

4.5.1 Local demand increase and/or generation reduction

Our TAPR identifies potential load developments and generation retirements that could trigger significant expenditure to augment the network to continue to meet our mandated reliability of supply standard. For these projects we propose contingent project triggers that identify the level of additional demand or reduction in generating capacity that will lead to failure to meet our mandated reliability of supply standards.

4.5.2 Market benefit

AEMO's 2024 Integrated System Plan (ISP)[66] identified significant network augmentations that could deliver net market benefits and are part of the optimal development path across the NEM. AEMO declared one of these projects, QNI Connect (Queensland – New South Wales Interconnector), to be actionable and requires that Powerlink and Transgrid commence the RIT-T assessment and publish a Project Assessment Draft Report (PADR).

[64] National Electricity Rules, clause 6A.8.1.
[65] National Electricity Rules, clause 6A.8.2.
[66] 2024 Integrated System Plan (ISP), Australian Energy Marker Operator, June 2024.

In the subsequent draft 2026 ISP[67], AEMO identifies one other Queensland project, the Gladstone Project, that would ordinarily have been declared as 'actionable' under the Rules but is instead flagged to be progressed under Queensland's PTI framework[68].

Beyond these ISP and PTI projects the Queensland Government, through its Energy Roadmap published in October 2025[69], has identified additional significant network augmentations that could deliver net market benefits during the 2027-32 regulatory period. A number of these projects have also been identified by AEMO in the draft 2026 ISP. However, as the final 2026 ISP will not be published until June 2026, we have included all the projects identified in the Energy Roadmap as contingent projects in our Revenue Proposal.

Central Queensland to South Queensland Reinforcement is not identified in the Energy Roadmap but has been identified by AEMO in the draft 2026 ISP as a future ISP project. The Rules provide that where an ISP identified project is declared actionable, it is automatically treated as a contingent project even if it was not identified as such in the relevant TNSPs' Revenue Proposal[70]. While we are not formally proposing Central Queensland to South Queensland Reinforcement as a contingent project, we have listed it below to aid transparency around the process and ensure customers are informed.

Our proposed contingent projects and their indicative costs are summarised in Table 4.10. We provide further detail on our proposed contingent projects and their triggers in Appendix 4.04.

Table 4.10 - Proposed contingent projects ($million real, 2026/27)

Project name	Type of trigger	Indicative total capital cost
Central to North Queensland Reinforcement	Market benefit/Energy Roadmap	209.0 to 1,788.0
Northern Bowen Basin Reinforcement	Additional customer demand	442.3
Gladstone Area Augmentation	Market benefit/Energy Roadmap	76.0 to 374.5
Central Queensland System Strength	Generation closure/minimum demand	450.0
Southern Queensland System Strength	Generation closure/minimum demand	225.0
South West Queensland Augmentation	Market benefit/Energy Roadmap	79.0
North Brisbane Area Network Development	Additional customer demand	247.9
Brisbane Area Transfer Capacity	Market benefit/Energy Roadmap	64.6
Surat Basin Area Network Development	Market benefit/Energy Roadmap	643.7

Actionable and future ISP projects identified in AEMO's draft 2026 ISP[71] and their indicative costs are summarised in Table 4.11.

[67] Draft 2026 Integrated System Plan (ISP), Australian Energy Marker Operator, December 2025.
[68] *Energy (Infrastructure Facilitation) Act 2024 (Qld),* Part 5.
[69] Energy Roadmap 2025, Queensland Government, October 2025.
[70] National Electricity Rules, clause 6A.8.2(a)(2).
[71] Draft 2026 Integrated System Plan (ISP) – Australian Energy Marker Operator, December 2025.

Table 4.11 - Actionable and Future ISP projects ($million real, 2026/27)

Project name	Type of trigger	Indicative total capital cost
QNI Connect	Market benefit/actionable ISP project	1,500 (1)
Central Queensland to South Queensland Reinforcement	Market benefit/future ISP project	1,500

(1) Cost shown is for Queensland component of project only.

Should any of these triggers occur, or should a project be declared an actionable ISP project, we will undertake the required regulatory processes, including RIT-T engagement. Further, should a CPA be made which offsets capital expenditure already identified in the ex-ante forecast (for example, the rebuild of a transmission line which results in refit works no longer being required), we will reduce the CPA by the appropriate amount.

4.6 Network Support/Non-Network Alternatives

We use network support as an alternative to network investment when it is economic to do so. We have well established processes for engaging with parties who are interested in the provision of non-network services. This includes our Non-Network Engagement Stakeholder Register where non-network solution providers can register to receive the details of potential non-network solution opportunities. We have also published a Network Support Contracting Framework, available on our website[72], as a general guide to assist potential non-network solution providers understand the key contracting principles that underpin our network support agreements.

For any given network limitation, the viability and specification of non-network solutions are first introduced in the TAPR. Further opportunities are then explored during the consultation and stakeholder engagement undertaken as part of any subsequent RIT-T. These established processes have been expanded to include requirements for inertia services and system strength services. In its 2025 Transition Plan for System Security, AEMO identified emerging system strength need in Queensland from 2027-28 with solutions underway. Further, AEMO identified two emerging inertia needs with remedial measures underway[73].

If any fault level or inertia shortfalls occur, we will consider the use of network support arrangements as alternatives to investment in new network assets. Table 4.12 identifies non-network alternative arrangements which commenced in the 2022-27 regulatory period.

Table 4.12 - Non-network alternative arrangements commencing in the 2022-27 regulatory period

RIT-T	Nature of Service	Commencement Date	Completion Date
Managing Voltages in South East Queensland RIT-T	Voltage Support Services	March 2023	November 2025
Addressing System Strength Requirements in Queensland from December 2025	System Strength Services	December 2025	December 2030
Addressing System Strength Requirements in Queensland from December 2025	System Strength Services	December 2025	December 2035

[72] Refer https://www.powerlink.com.au/non-network-solutions.
[73] 2025 Transition Plan for System Security, Australian Energy Market Operator, December 2025.

4.7 Deliverability of future expenditure

When developing this capital expenditure forecast, we have predominantly used a bottom-up approach. The resulting forecast was subsequently tested and adjusted using top-down methods that considered our historical capital expenditure trends over the last 10 years.

We have a proven ability to deliver capital projects to meet the needs of Queensland customers for a safe, reliable and cost-effective supply of electricity. Our forecast capital expenditure is more than 60% higher than the actual/forecast expenditure for the current regulatory period and as a result we have taken several significant steps in the current period to ensure we have the capability to deliver this quantum of work going forward.

- We enhanced our portfolio risk management approach to support structured reinvestment planning across asset classes and help optimise project timing to manage overall network risk.
- We expanded our regional workforce capacity in response to forecast increases in workload across central and northern Queensland.
- We are consolidating our transmission lines and substations outsourcing arrangements under a newly established panel agreement with contractors to support the efficient delivery of construction works.
- We have leveraged our positive relationships with suppliers to secure new manufacturing capability to reduce lead times and procurement costs.

In addition to these steps, we have assessed the deliverability of the capital expenditure forecast included in this Revenue Proposal, specifically considering the network capital program. Our deliverability assessment, included as Appendix 4.09, considered a range of challenges that impact the deliverability of our network capital expenditure program, including resource capacity and capability, land access and approvals, supply chain capacity, and network constraints and outage availability.

The assessment reviewed our business as usual approach to portfolio management and extended this to 2027-32 capital expenditure forecast. The assessment also considered the deliverability within the context of Powerlink's broader capital expenditure programs, not covered by the revenue determination process, such as the Gladstone Project and non-regulated customer connection works. Powerlink considers that our assessment demonstrates that our capital expenditure forecast for the 2027-32 regulatory period is deliverable.

4.8 Capital expenditure forecasting methodology

We have developed our capital expenditure forecast consistent with the requirements of the Rules[74] and our Expenditure Forecasting Methodology, which was provided to the AER in June 2025 (refer Appendix 4.03). We have also had regard to the AER's 2024 Industry Practice Application Note for Asset Replacement Planning[75].

Information on proposed transmission investments within a 10-year outlook is published in our TAPR[76] and related material. We also refer to AEMO's 2024 ISP. These longer-term plans are particularly relevant to identify contingent projects, which are discussed in Section 4.5.

As we developed our methodology and forecasts for the 2027-32 regulatory period, we engaged with our customers and stakeholders (refer Chapter 3 Customer Engagement). We also regularly engage with our

[74] National Electricity Rules, clause 6A.6.7.
[75] Industry practice application note - Asset replacement planning, Australian Energy Regulator, July 2024.
[76] 2025 Transmission Annual Planning Report, Powerlink, October 2025.

customers and stakeholders on planning and other business-related matters in the normal course of business, including at our annual Transmission Network Forum[77].

4.8.1 Capital expenditure categories

We applied the same categories of capital expenditure drivers for our forecast capital expenditure that were applied in our 2023-27 Revenue Proposal. Capital expenditure categories, and the prescribed transmission services they relate to, are shown in Table 4.13.

Table 4.13 - Powerlink's capital expenditure categories

Capital expenditure category	Definition	Prescribed transmission service
Network load driven		
Augmentations	Relates to augmentations defined under the Rules. Typically, these include projects such as the construction of new lines, substation establishments and reinforcements or extensions of the existing network.	Transmission Use of System (TUOS) services and exit services
Connections	Works to facilitate additional connection point capability between Powerlink and Distribution Network Service Providers (DNSPs) or other TNSPs. Associated works are identified through joint planning with the relevant Network Service Provider.	Exit services
Easements	The acquisition of tenure, including easements for transmission lines and freehold land for substations and communication sites, to facilitate the projected expansion and reinforcement of, and reinvestment in, the transmission network. Activities may include obtaining primary approvals, addressing cultural heritage and native title rights, and managing community engagement and social performance considerations.	Common services, TUOS services and exit services
Network non-load driven		
Reinvestments	Relates to reinvestment to meet the expected demand for prescribed transmission services. Expenditure is primarily undertaken due to end of asset life, asset obsolescence, asset reliability or safety requirements. A range of options is considered for asset reinvestments, including removing assets without replacement, non-network alternatives, life extension to extend technical life or replacing assets with assets of a different type, configuration or capacity. Each option is considered in the context of future capacity needs accounting for forecast demand.	Common services, TUOS services and entry/exit services
System Services	Investments to meet overall power system performance standards and support the secure operation of the power system. This includes the provision of system strength services and inertia services.	Common services
Security / Compliance	Expenditure undertaken to ensure compliance with amendments to various technical, safety or environmental legislation. In addition, expenditure is required to ensure the physical security (as opposed to network security) of Powerlink's assets.	Common services, TUOS services and entry/exit services

[77] Refer https://www.powerlink.com.au/engagement-forums.

Capital expenditure category	Definition	Prescribed transmission service
Other	All other expenditure associated with the network which provides prescribed transmission services, such as communications system enhancements, improvements to network switching functionality and insurance spares.	Common services
Non-network		
Business Information Technology (IT)	Expenditure to maintain IT capability, replace or improve business system functionality, assist in meeting regulatory requirements, enhance productivity, and improve cyber security of business systems.	Common services
Support the Business	Expenditure to replace or improve business requirements including the areas of commercial property, vehicles and moveable plant, for instance to address safety.	Common services

4.8.2 Our hybrid forecasting approach

We continue to evolve a hybrid approach to developing our capital expenditure forecasts, which integrates top-down and bottom-up methods.

We have built on the experience, input and feedback gained during our previous revenue determination process and have further refined and improved this approach for the 2027-32 regulatory period. As part of this improvement, we targeted development of project-specific supporting justification for at least 80% of our total forecast capital expenditure. Depending on the type and stage of development of the project, this may include asset condition assessment reports, applicable asset strategies, project scopes, project estimates, network planning assessments and risk-cost quantification. For lower dollar value replacement capital expenditure projects our forecasting approach will be based on a bottom-up view of project needs developed using forecast asset-specific health indices and informed assumptions in respect of the option presented.

This approach provides several advantages in that it:

- reduces the resources needed to prepare our Revenue Proposal compared to an entirely bottom-up approach
- balances the desire of stakeholders to understand the technical and economic justification for significant forecast investments, while recognising the uncertainty of forecasting capital expenditure needs many years in advance when the technical demands on the transmission network are rapidly changing
- assists the AER and stakeholders in terms of the time, effort and cost to review and assess our Revenue Proposal, and
- addresses concerns expressed by the AER over the use of its Repex Model in our 2023-27 Revenue Proposal.

Some categories of non-network capital expenditure will be forecast using a top-down methodology, whereby the future requirements are based upon a trend of historical expenditure. This will include adjustments to historical capital expenditure where appropriate to remove specific expenditure that does not represent an ongoing trend. Details of the hybrid approach can be found in our Expenditure Forecasting Methodology and a summary is presented in Table 4.14.

Table 4.14 - Summary of Powerlink's hybrid approach

Approach	Capital Expenditure Category	Supporting Information
Bottom-up	Approved projects (all categories) Load driven capital expenditure Reinvestment System Services Security/Compliance – major programs Other – major programs One-off expenditure needs, incl. major non-network capital expenditure Contingent projects [(1)]	Description of need, preparation of project specific scope, estimate, planning statement and risk-cost assessment. Note: the level of documentation provided will vary depending on the maturity of the project.
Top-down (trend analysis)	Security/Compliance – low value, recurrent items Other – low value, recurrent items Non-network capital expenditure – low value, recurrent items	Use of a forecasting methodology similar to the base-trend-step approach for forecasting operating expenditure.

(1) Contingent projects are not included in the ex-ante capital expenditure forecast.

Regardless of the methodologies used to forecast our capital expenditure for the purpose of this Revenue Proposal, detailed bottom-up analysis continues to be required and prepared to support final investment approval in our normal course of business. Much of our network capital expenditure is also subject to public consultation through the RIT-T process.

4.8.3 Cost estimating methodology

We develop project cost estimates based on a defined scope of work to address an identified investment need.

Depending on the category of project, identified investment needs may be triggered by growth in customer demand exceeding existing network capacity, the condition or obsolescence of existing network assets, the need to enhance building facilities, or the need to upgrade cyber security protection.

We produce our project estimates using a first principles approach, where the estimate is calculated based upon the specific resources and quantities required to complete the defined scope of works (e.g. labour, equipment, materials and subcontracts). We also identify and cost items particular to the project site to account for project-specific site conditions.

Project estimates provide the basis for economic analysis, management decisions, budgets and cost control. Estimates of increasing accuracy may be produced to support these activities as a project progresses, and engagement occurs with external providers.

Network project estimate types

We adopt two formal estimating methodologies for network projects. This reflects a fit-for-purpose approach to estimating based on project complexity, risk and expected cost as detailed below.

- Concept Estimates: produced in response to a high-level project scope requiring the consideration of multiple options, with a wider cost accuracy range these are typically developed for future investment needs or to support the detailed investigation of a confirmed investment need.

- Project Proposals: developed in response to a detailed project scope for a single option, which enables a narrower cost accuracy range, to support the full financial approval of a project consistent with Powerlink's corporate governance framework.

To establish the capital expenditure forecast in our Revenue Proposal, we scoped and estimated a single, most-likely, option using the Concept Estimate approach. All projects will undergo full option analysis as part of business as usual processes, which also includes application of the RIT-T consultation process where appropriate. This will require a new Concept Estimate to compare option costs on a like basis before the preferred option is selected and a Project Proposal completed to provide a more detailed scope and estimate.

Network project estimate classes and accuracy

We produce estimates in line with international recommended practice[78] that are informed by the level of specific project information available at the time the estimate is prepared. The most common class of estimate for Concept Estimates and Project Proposals are class 5 and class 3 respectively.

Table 4.15 provides the typical level of detail required and accuracy of each class of estimate produced.

Table 4.15 - Estimate classes and accuracy (Source: AACE International, Powerlink)

Estimate Class	Maturity of Project Definition	Typical Accuracy Range	Typical Estimate Type
Class 5	0% to 2%	-50% to +100%	Concept Estimate
Class 4	1% to 15%	-30% to +50%	
Class 3	10% to 40%	-20% to +30%	Project Proposal
Class 2	30% to 75%	-15% to +20%	
Class 1	65% to 100%	-10% to +15%	

The estimate classification is derived from the maturity of the data that makes up the project definition, such as the specific items of equipment required, quantities of construction materials, and construction staging. Each project estimate is based upon known quantities where available but will also include assumed quantities based upon recent project examples where necessary.

4.8.4 Capital Expenditure Model

Our Capital Expenditure Model compiles all the project cost estimates that make up our capital expenditure forecast and transforms them to produce the key data necessary to support our Revenue Proposal. This includes:

- forecast capital expenditure inputs to the Post Tax Revenue Model (PTRM), and
- forecast capital expenditure data to be included in the Reset Regulatory Information Notice (RIN) templates.

Depending on where a project is in its lifecycle, its forecast expenditure will be expressed as either:

- $ nominal – where the project is already approved; or
- $ real, 2025/26 – where the project is not approved and an estimate has been prepared for the purposes of the Revenue Proposal.

[78] Association for the Advancement of Cost Estimating (AACE International), Recommended Practice No. 18R-97.

Where forecast expenditure is expressed in $ nominal the expenditure is de-escalated to $ real, 2026/27 using the forecast of inflation from the PTRM. Where forecast expenditure is expressed in $ real, 2025/26 the expenditure is first escalated to a $ nominal basis using the appropriate real price escalators set out in Chapter 6 Escalation Rates. The resulting $ nominal expenditure is then de-escalated to $ real, 2026/27 using the forecast inflation from the PTRM.

Each project is assigned a project type, such as Power Transformer, Secondary Systems, IT – Non-recurrent, etc. The project type specifies the percentage breakdown of expenditure into the categories of direct materials, direct labour, contract costs and other costs. This breakdown allows the appropriate category specific real cost escalation to be applied to each project in the forecast. Each project also includes a percentage breakdown of the forecast expenditure into asset classes.

This process ensures all forecast capital expenditure is expressed on a consistent basis that meets the requirements of the PTRM and supports the reporting for the Reset RIN.

4.8.5 Inputs and assumptions

Powerlink's Board Directors certified the reasonableness of the key assumptions that underlie our capital expenditure forecast (refer Appendix 1.01 Board Certification of Key Assumptions). We have also included the key inputs and assumptions for capital expenditure in Attachment 1.

Table 4.16 describes other inputs and assumptions we applied to develop our forecast capital expenditure for the 2027-32 regulatory period.

Table 4.16 - Inputs and assumptions for our capital expenditure forecast

Input/assumption	Description
Forecast demand and generation	• The electricity demand forecast adopted for our Revenue Proposal is the Central Scenario outlook in Powerlink's 2025 Transmission Annual Planning Report, published in October 2025. • The location and capacity of existing and committed generation in Queensland is sourced from AEMO, unless modified following specific advice from relevant participants. • Information about existing and committed embedded generation and demand management within distribution networks is provided by Distribution Network Service Providers (DNSP).
Transmission reliability of supply standard and Asset Planning Criteria	• Clause 6.2 of our Transmission Authority[79] obligates us to plan and develop the transmission network such that mandated power quality and reliability of supply standards will be met. • This includes a requirement to plan and develop the transmission network to be able to supply the forecast maximum demand, with no more than 50MW or 600MWh of customer supply curtailed, even with the most critical network element out of service. • The Asset Planning Criteria sets out the planning assumptions made when assessing compliance against the required reliability of supply standard.

[79] Transmission Authority Number T01/98 issued by the Queensland Energy Regulator under the Electricity Act 1994 (Qld).

Input/assumption	Description
Integrated System Plan	• AEMO's 2024 ISP sets out a whole-of-system, least-cost development path for the NEM over a 20-year outlook. • Where the ISP identifies future augmentation of a part of Powerlink's transmission network in the optimal development path we will consider reinvestment in existing assets, and future easement requirements in that context.
System Security Reports	• AEMO's 2025 Transition Plan for System Security reports includes forecasts of system security services requirements for system strength, inertia and network support and control ancillary services (NSCAS). Powerlink is required to procure prescribed transmission services (network and/or non-network) to meet these forecast needs in its capacity as System Strength Service Provider (SSSP), Inertia Service Provider, and TNSP respectively.
Asset Reinvestment Criteria	• Defines the methodology used to assess the need and timing for intervention on network assets to ensure that industry compliance obligations are met.
Asset information	• Where required for the purposes of forecasting, we have sourced this information from our Enterprise Resource Planning database SAP.
Cost escalators and risk	• The main input cost components of our capital expenditure forecasts are labour costs (internal and external) and general plant and equipment. • The cost escalators we have applied are outlined in Chapter 6 Escalation Rates.

4.8.5.1 Demand and energy forecast

The demand forecast is developed through a methodology that projects future electricity demand. Historical actual demand and energy data forms the foundation, identifying trends and patterns in consumption. These data points establish a baseline for understanding usage over time.

A further seven additional input datasets are included to form the final forecast projections. These inputs are sourced from AEMO, Energy Queensland and external consultants for market or industry trends. Powerlink also uses internal data, including confidential customer information. The annual forecast process requires all TNSP connected customers to provide a 10-year demand forecast and through this process several existing connections have signalled increases in demand and energy due to decarbonisation ambitions.

The resultant central scenario demand forecast is shown in Figure 4.3 compared with AEMO's 2024 and 2025 Electricity Statement of Opportunities (ESOO) forecasts. The alignment of Powerlink's 2025 forecast with AEMO's 2025 Step Change scenario forecast is significantly closer compared to the 2024 forecasts from both organisations. Powerlink's 10-year forecast is very similar to AEMO's with differences due to the input assumptions used.

Over the 2027-32 regulatory period, Powerlink's 2025 Central scenario coincident maximum delivered demand is forecast to grow by 14.4%. In preparing the 2027-32 capital expenditure forecast Powerlink has used this load forecast[80] to identify load driven limitations that will require expenditure during the 2027-32 regulatory period. This assessment has been done applying the principles of the Asset Planning Criteria.

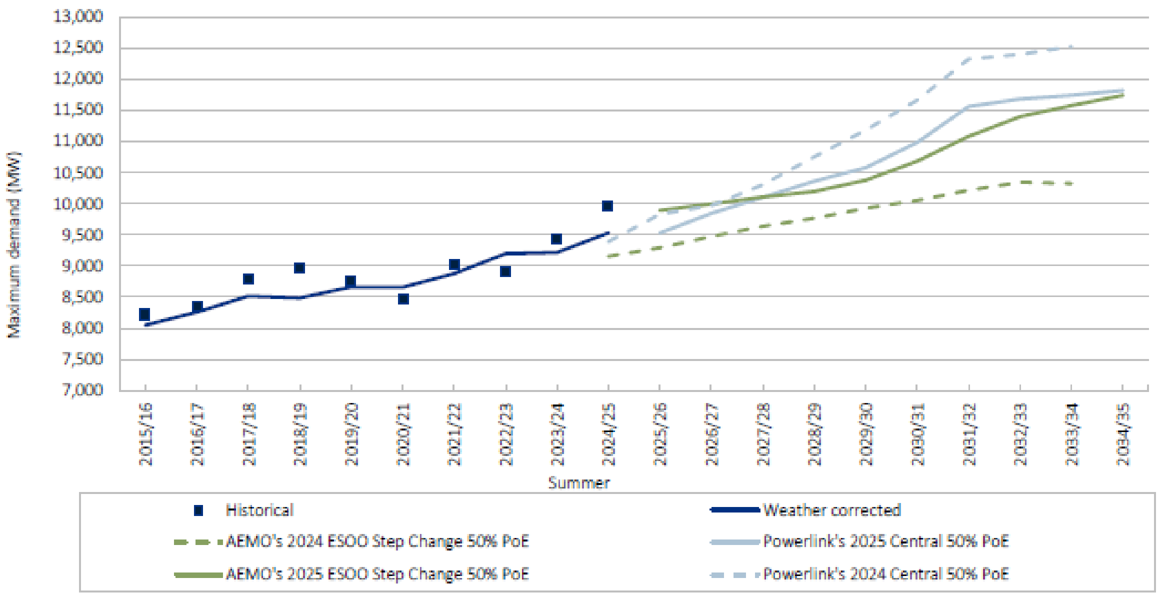
The main contributing factor is the electrification of industry located within the Gladstone region. Network limitations due to this demand growth are being addressed through the current Gladstone Project PTI process.

Other forecast demand growth can generally be accommodated within the existing network capacity. However, there are certain areas where the planning standard is nearing its limit. Joint planning is being undertaken to determine the required timing for augmentation in these areas. These include Goodna, Mudgeeraba and Loganlea substations. In all cases special protection schemes and load transfers are being investigated to defer the respective augmentations. The required timing for any augmentation will also be reassessed post the 2025/26 summer demand forecast update.

The specific demand impacts of the 2032 Olympics, including where any new load may materialise, are still being understood by Energy Queensland. Until these assumptions are confirmed, the resulting impacts on the transmission network cannot yet be assessed.

Pending the outcome of these assessments, the load driven capital expenditure may be updated in the 2027-32 capital expenditure forecast in the Revised Revenue Proposal.

Figure 4.2 - Comparison of the 2025 TAPR demand forecast with AEMO's 2024 and 2025 ESOO demand forecast

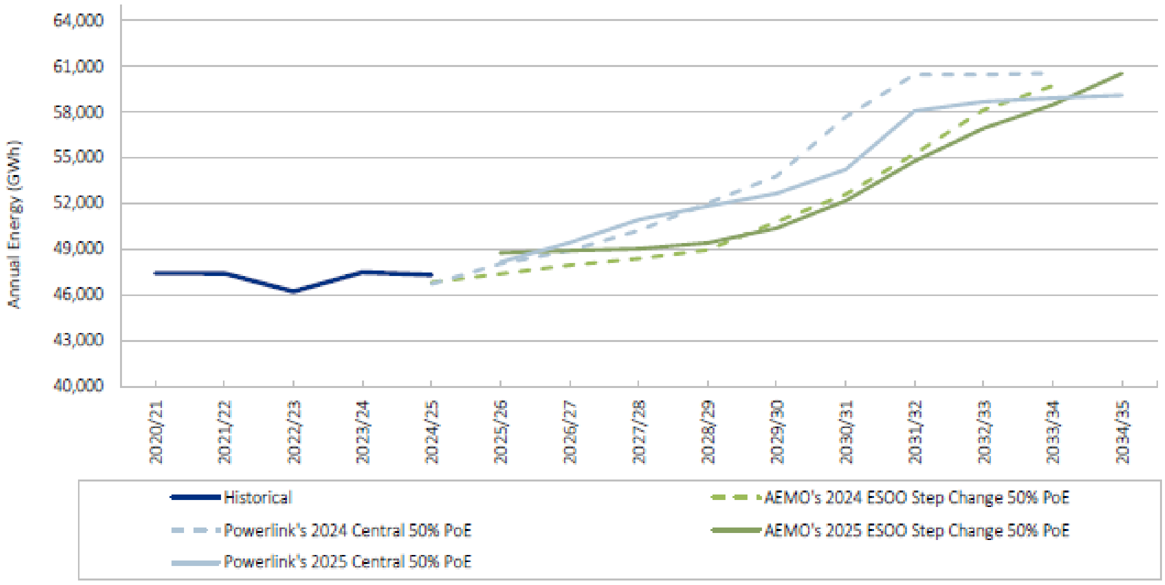


Note: AEMO's 2024 and 2025 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison.

The forecast annual energy consumption (Figure 4.4) shows steady average annual growth over the forecast horizon. Over the 2027-32 regulatory period the delivered energy is forecast to grow by approximately 14%.

[80] Powerlink's forecasting process also provides sub regional forecasts at more granular levels. This enables Powerlink to assess demand drivers relevant to the geographical area being assessed

Figure 4.3 - Comparison of the 2025 TAPR energy forecast with AEMO's 2024 and 2025 ESOO consumption forecast



Note: AEMO's 2024 and 2025 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison.

4.8.5.2 Asset planning criteria

Powerlink's Transmission Authority requires that we plan and develop the network so that only a limited amount of customer demand and energy is at risk of not being supplied during the most critical single contingency event. These demand and energy limits are set in the Transmission Authority at 50MW and 600MWh.

The Transmission Authority also includes a requirement to apply good electricity industry practice which, in turn, necessitates the use of a range of supporting technical standards. The reliability of supply standard, along with the supporting technical standards, comprises our Asset Planning Criteria Framework. Our Asset Planning Criteria Framework is provided as a supporting document to our Revenue Proposal.

4.8.5.3 Asset reinvestment criteria

Powerlink's Asset Management System ensures assets are managed in a manner consistent with the Asset Management Policy and overall corporate objectives to deliver safe, reliable and cost-effective services. We demonstrate this by adopting a proactive approach to asset management that optimises whole of life-cycle costs, benefits and risks, while ensuring compliance with applicable legislation, regulations, standards, statutory requirements, and other relevant instruments.

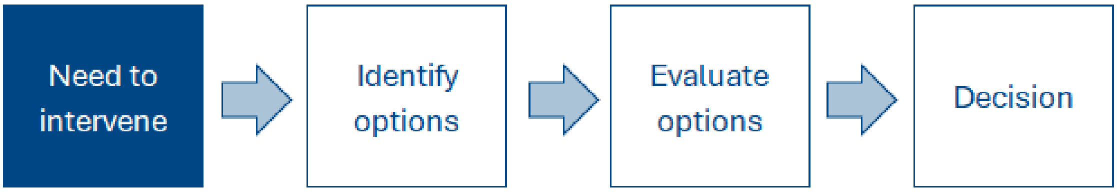
Our Asset Reinvestment Criteria Framework defines the methodology that we use to assess the need and timing for intervention on network assets to ensure that industry compliance obligations are met. The methodology improves transparency and consistency within the asset reinvestment process, enabling our customers and stakeholders to better understand the criteria applied to determine the need and timing for asset intervention.

This framework is relevant where the asset condition changes so it no longer meets its level of service or complies with a regulatory requirement. The reinvestment category is triggered when the existing asset has degraded over time and no longer provides the required standard of service as prescribed within applicable legislation, regulations and standards.

The trigger to intervene needs to be identified early enough to provide an appropriate lead time for the asset reinvestment planning and assessment process. The need and timing for intervention are defined when business as usual activities (including routine inspections, minor condition based and corrective maintenance and operational refurbishment) indicate the network asset is no longer able to meet prescribed standards of service due to deteriorated asset condition.

Our Asset Reinvestment Process, shown in Figure 4.5, enables timely, informed and prudent investment decisions to be made that consider all economic and technically feasible options, including non-network alternatives or opportunities to remove assets where they are no longer required. An assessment of the need and timing for intervention is the first stage of this process.

Figure 4.4 - Asset reinvestment process



The principles set out in the Asset Reinvestment Criteria Framework underpin the timing of specific reinvestment projects in this Revenue Proposal. The Asset Reinvestment Criteria Framework is provided as a supporting document to our Revenue Proposal.

5 Operating Expenditure

5.1 Introduction

This chapter provides an overview of Powerlink's historical performance against the Australian Energy Regulator's (AER's) allowances for operating expenditure during the current 2022-27 regulatory period and outlines our operating expenditure forecasts for the 2027-32 regulatory period. Our operating expenditure enables the operation and maintenance of our network, as well as the business activities that support the delivery of prescribed transmission services[81].

Key highlights:

2022-27 regulatory period

- We forecast total operating expenditure of $1,517.2 million for the 2022-27 regulatory period. This is $253.4 million (20%) higher than the AER's adjusted allowance of $1,263.8 million. These figures are exclusive of debt raising costs.
- Our performance under the AER's economic benchmarking approach has decreased over the course of the current regulatory period, broadly reflecting the industry trend.

2027-32 regulatory period

- Our total operating expenditure forecast for the 2027-32 regulatory period is $1,810.2 million, or $1,832.2 million including debt raising costs, which is $293.0 million (19%) higher than the actual/forecast operating expenditure for the 2022-27 regulatory period (excluding debt raising costs).
- Our forecast is based on the AER's preferred base-trend-step methodology.
- We proposed 2025/26 as our base year as the revealed costs will be most representative of our ongoing efficient recurrent costs at the time the revised Revenue Proposal is submitted in December 2026.
- We engaged HoustonKemp to perform an independent assessment of the efficiency of our proposed base year expenditure. HoustonKemp's analysis shows that:
    - Powerlink's operating expenditure efficiency is forecast to decline in 2024/25 and 2025/26 due to increases in operating expenditure, and
    - comparative data is not available at this time to determine whether the forecast decline in operating expenditure efficiency reflects the broader industry trend.
- Powerlink considers that the AER's economic benchmarking approach, which provides historical context, does not reflect the rapid change in our operating environment.
- We have included three step changes at a total of $85.1 million in our operating expenditure forecast. The step changes reflect material costs not included in our base year to:
    - uplift physical security
    - transition to cloud-based computing solutions, and
    - enhance overnight network monitoring in our control room.
- We have included category specific forecasts for the Australian Energy Market Operator (AEMO) participant and cyber security fees, network support payments and debt raising costs.

[81] Unless otherwise stated, references to total operating expenditure reflect underlying operating expenditure, which excludes movements in provisions, debt raising and network support costs. This is explained further in Sections 5.3 and 5.7.

5.2 Regulatory requirements

The National Electricity Rules (Rules)[82] require that our Revenue Proposal provide information related to our actual/forecast operating expenditure over the current regulatory period and that the AER also has regard to such expenditure when considering our proposed forecast expenditure[83].

The Rules[84] also require that we must submit our forecast operating expenditure for the 2027-32 regulatory period in our Revenue Proposal.

5.3 Historical operating expenditure

This section summarises our historical operating expenditure for the 2022-27 regulatory period, consistent with the requirements of the Rules[85].

5.3.1 Historical operating expenditure summary

Table 5.1 shows our actual/forecast operating expenditure for the current regulatory period by expenditure category. Expenditure for the 2023 to 2025 financial years are audited actuals while the 2026 and 2027 financial years are based on our current expenditure forecasts.

[82] National Electricity Rules, Schedule 6A.1, clause S6A.1.2(7).
[83] National Electricity Rules, clause 6A.6.6(e)(5).
[84] National Electricity Rules, clause 6A.6.6 and Schedule 6A.1, clause S6A.1.2.1.
[85] National Electricity Rules, Schedule 6A.1, clause S6A.1.2(7).

Table 5.1 - Operating expenditure - actual/forecast ($million, real 2026/27)

	2023	2024	2025	2026 forecast	2027 forecast	Total
Controllable operating expenditure						
Field Maintenance	84.5	93.7	102.6	116.0	128.7	**525.6**
Operational Refurbishment	36.0	37.0	48.4	42.4	45.5	**209.2**
Maintenance Support	19.0	22.2	27.5	30.3	31.2	**130.2**
Network Operations	22.4	26.7	36.9	36.6	41.1	**163.7**
Asset Management Support	30.8	35.5	40.9	41.2	38.6	**187.0**
Corporate Support	41.3	54.9	36.9	41.6	36.5	**211.0**
Total controllable operating expenditure	**234.0**	**270.0**	**293.2**	**308.1**	**321.6**	**1,426.8**
Other operating expenditure						
Insurance Premiums	9.2	9.6	8.6	9.1	9.9	**46.3**
Self-Insurance	0.9	0.9	1.0	2.0	2.3	**7.0**
Australian Energy Market Commission (AEMC) Levy	8.1	6.2	6.8	6.0	6.2	**33.2**
Network Support (1)	0.6	1.2	2.1	-	-	**3.8**
Debt raising costs	0.2	0.1	0.1	0.4	0.6	**1.4**
Total other operating expenditure	**19.0**	**18.0**	**18.5**	**17.5**	**18.9**	**91.8**
TOTAL OPERATING EXPENDITURE (2)	**253.0**	**288.0**	**311.7**	**325.6**	**340.4**	**1,518.6**
TOTAL OPERATING EXPENDITURE (excl. debt raising costs)	**252.8**	**287.8**	**311.6**	**325.1**	**339.9**	**1,517.2**

(1) Network support incorporates both system security network support payments and network alternative support payments. From 1 December 2024, system security network support payments were recovered as a direct pass through via prescribed transmission prices. We have not included a forecast for 2026 and 2027.
(2) Total operating expenditure includes costs associated with AER approved pass throughs of $2.0 million.

5.3.2 Performance against allowance

In determining the Maximum Allowed Revenue (MAR) that Powerlink may recover during a regulatory period, the AER provides an allowance for the prudent and efficient operating expenditure needed to achieve the operating expenditure objectives. The AER's allowance for the 2022-27 regulatory period was $1,263.8 million (exclusive of debt raising costs and adjusted for approved pass throughs), restated in real 2026/27 terms.

We expect total operating expenditure to be $1,517.2 million which is $253.4 million (20%) higher than the AER's total allowance for the 2022-27 regulatory period. These figures are exclusive of debt raising costs. Table 5.2 outlines the annual trend in allowed and actual operating expenditure over the 2022-27 regulatory period.

Table 5.2 - Operating expenditure - allowance vs actual/forecast ($million real, 2026/27)

	2023	2024	2025	2026 forecast	2027 forecast	Total
AER allowance (1)	250.4	253.5	252.5	252.8	252.7	**1,261.9**
Approved pass throughs	0.9	0.9	0.1	0.0	0.0	**2.0**
Adjusted allowance (2)	251.3	254.4	252.6	252.8	252.7	**1,263.8**
Actual/forecast (3)	252.8	287.8	311.6	325.1	339.9	**1,517.2**
Difference	1.5	33.4	59.0	72.3	87.2	**253.4**
Difference (%)	1%	13%	23%	29%	35%	**20%**

(1) Exclusive of debt raising costs. There was an allowance of $0 for network support costs.
(2) Actual/forecast expenditure includes costs associated with AER approved pass throughs of $2.0 million.
(3) Exclusive of debt raising costs.

As discussed in Chapter 2, Powerlink's operating environment has changed significantly since our previous Revenue Proposal was lodged in January 2021. This change has impacted our cost performance in operating expenditure over the 2022-27 regulatory period, and we have experienced cost increases in several controllable and non-controllable operating expenditure categories as outlined in the following sections.

5.3.2.1 Controllable operating expenditure

Controllable operating expenditure is expected to be $248.2 million (21%) higher in the 2022-27 regulatory period than the AER allowance. The key drivers for this are discussed below.

Demand for skilled labour

Growing demand for skilled labour resources is one of many factors driving increased operating expenditure in the 2022-27 regulatory period. This was illustrated in Chapter 2 Operating Environment. Additionally, a report on AEMO's 2024 Integrated System Plan noted that the number of electricity sector jobs required is expected to increase steeply for all scenarios in the run up to 2030[86].

Since the commencement of the 2022-27 regulatory period, Powerlink has substantially increased its workforce in response to changes in government policy, emissions reduction targets at the time and major planned investments. We have expanded our regional workforce in response to increases in workload across central and northern Queensland and have grown our teams to operate our increasingly complex network.

In addition to this, new enterprise agreements came into effect from February and March 2024 and included increases to base salary, superannuation and allowances, as well as changes to conditions. The agreements reflect the increased demand for skilled resources within the energy sector and is critical to enable Powerlink to secure and retain the resources to deliver its capital and operating works in the current 2022-27 and upcoming 2027-32 regulatory periods.

Combined, Powerlink's growth in workforce and wages account for the majority of the additional operating expenditure.

[86] The Australian Electricity Workforce for the 2024 Integrated System Plan: Projections to 2050, UTS Institute for Sustainable Futures, September 2024.

Complexity

The transition of the energy system within Queensland is well underway. To accommodate the increasing integration of large-scale inverter-based resources, energy storage and rooftop solar, there are new regulatory obligations for services such as system strength, while the operating envelope (the difference between maximum demand and minimum demand) continues to increase. Powerlink is learning and adapting to new ways in which the grid is being used.

The rapidly increasing technical complexity of operating the transmission network introduces several key operational challenges which result in additional costs. These include the need for more frequent operator intervention, an increasing number of alarms, a rise in the labour effort required for scheduling, planning and management of outages, and an increase in complex switching activities and network support activations to ensure the network operates securely and reliably. We require the development of more specific operating and contingency plans, schemes and complex operating strategies to maintain power system security and optimise utilisation of installed network assets.

These factors have driven additional operating expenditure within the current regulatory period and have also been considered in the development of operating expenditure forecasts for the 2027-32 regulatory period (refer Section 5.6.1). The cost impact is in the 2022-27 period is forecast to be $58 million and is driven by the additional network operations resources required to address and mitigate the increased complexity.

New regulatory and compliance obligations

Powerlink is required to comply with the *Security of Critical Infrastructure Act 2018 (SOCI Act)*. Amongst other obligations, the SOCI Act requires owners of critical infrastructure to implement risk management plans to mitigate material risks associated with cyber and information hazards, personnel hazards, supply chain hazards, and physical and natural hazards.

In the development of our 2023-27 Revenue Proposal, there was uncertainty about the scope and timing of upcoming obligations, as well as the impacts of relevant legislation, which were not fully understood. As a result, a step change did not form part of our Revenue Proposal.

Powerlink has incurred additional costs arising from the SOCI Act related to physical security obligations. This has contributed over $14.5 million to the operating expenditure overspend in the current 2022-27 period, with phased implementation continuing into the 2027-32 regulatory period.

In September 2025, Powerlink lodged a cost pass through application with the AER for a portion of the additional costs directly attributable to the uplift of physical security to comply with the SOCI Act. As the outcome of this application is not yet known, we have not included the proposed pass through amount in the AER allowance for operating expenditure at this time. The AER is expected to make a decision on this matter in early 2026.

The cyber security threat to Powerlink is high[87] and a successful attack on its critical infrastructure could have severe consequences. During the 2022-27 regulatory period we have evolved our cyber security focus and capability and have now achieved the required level of maturity under the Australian Energy Sector Cyber Security Framework (AESCSF)[88] as flagged in our 2023-27 Revenue Proposal. The release of version 2 of the AESCSF in 2023 included a 37% increase in the number of practices and anti-patterns[89] (currently at 354) required

[87] The Australian Cyber Security Centre (ACSC) considers electricity transmission a high criticality cyber target.
[88] The Australian Energy Sector Cyber Security Framework (AESCSF) is a cyber security framework developed for the Australian energy sector that leverages recognised industry frameworks and references global best-practice control standards.
[89] An anti-pattern is a poor cyber security behaviour or activity that hinders maturity. It is the opposite of good practice.

to be implemented or addressed to maintain the maturity level. This heightened focus and escalating risk in the cyber threat environment has had a significant effect on cyber security related operating expenditure. The operating costs of maintaining this maturity level continue to increase and contribute over $20 million to the operating expenditure overspend.

5.3.2.2 Non-controllable operating expenditure

In total, we forecast to exceed the AER's 2022-27 regulatory allowance for non-controllable operating expenditure by $7.1 million. This excludes debt raising costs.

Network Support

We forecast to incur network support costs during the 2022-27 regulatory period of $3.8 million. This incorporates both system security network support payments and network alternative support payments. To date, the AER has approved to pass through $2.0 million in relation to network support payments, consistent with Powerlink's network support cost pass through applications.

There was considerable uncertainty around potential network support costs with no contracts in place at the time of lodging our 2023-27 Revenue Proposal in January 2021, and the possibility for emerging energy market dynamics to alter the requirements for network support payments. For this reason, we sought an allowance of $nil for network support costs at that time.

Subsequently, in September 2023, we identified the need for network alternative support services after finalising a Regulatory Investment Test for Transmission (RIT-T) for managing voltages in South East Queensland[90]. The final recommendation comprised the installation of one bus reactor at the Belmont Substation, and network support services at times of reactive power shortfall, while further reactive support from other non-network developments emerge. As this was identified as a trade-off between operating expenditure and capital expenditure that was provided for in our capital expenditure allowance, Powerlink did not make a network support cost pass through application to the AER for these services.

While we forecast to incur system security network support costs over the remainder of the 2022-27 regulatory period, these have not been included in our operating expenditure forecast in line with the Australian Energy Market Commission's (AEMC's) final Rule for the Improving Security Frameworks for the Energy Transition Rule change[91]. This resulted in removal of the need to forecast non-network system security costs as part of a revenue determination process. Instead, the AEMC determined that these costs be recovered by an annual forecasting and true up process, which forms part of the annual prescribed transmission service pricing process – effectively a direct pass through to customers. These changes to cost recovery commenced in December 2024.

[90] Information on the Regulatory Investment Test for Transmission – Managing voltages in South East Queensland can be found on the Powerlink website.
[91] National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024 No. 9, Australian Energy Market Commission.

Insurance

Insurance costs (premiums and self-insurance) for the 2022-27 regulatory period are forecast to be $5.0 million (10.4%) higher than the AER allowance. At the time of preparing our 2023-27 Revenue Proposal the insurance industry was in a hard phase[92] of the cycle, creating uncertainty around future costs. Increases are anticipated to continue into the 2027-32 regulatory period, but at a rate aligned with a 'softening' global insurance market. This is discussed further in Section 5.10.1.

5.3.3 Productivity initiatives

In our 2023-27 Revenue Proposal, we proposed an annual productivity target higher than the industry average and identified several productivity initiatives to support this target. We have achieved some productivity savings, partially offsetting the impacts of the cost increases highlighted in Section 5.3.2. Collectively, these equate to approximately $5.6 million annually in savings or avoided costs and are discussed further below.

5.3.3.1 Materials supply chain and direct purchasing

We have focused on delivering productivity improvements through digitisation, process optimisation and commercial innovation in our materials supply chain and direct purchasing functions. We have increased the number of procurement panels and period agreements which has enabled more structured and competitive sourcing, consolidated spend, reduced sourcing cycle times and improved process efficiency. We are implementing a Source-to-Contract platform which will automate workflow, improve transparency, enhance compliance and enable better data-driven decision making across the procurement lifecycle.

5.3.3.2 Vegetation management

We have improved how we plan, prioritise, coordinate and verify vegetation works across our network including trialling satellite data capture technology. Combined with the shift to a statewide vegetation contract, this has seen a reduction in our vegetation management costs, with the cost per span decreasing since 2023.

5.3.3.3 Improving the efficiency of central processes and activities

We have progressed the implementation of enhanced technology and tools to support frontline teams. Through this program, we have realised benefits in the utilisation of our field-based teams with improvements in work scheduling and packaging.

5.3.3.4 Office refit

In the 2022-27 regulatory period we have shifted to shared working arrangements, maximising the utilisation of office space at our Virginia site, and deferring the need to establish additional office space.

5.3.3.5 Business Information Technology (IT)

We continue to deliver on Business IT replacements, software upgrades and rationalisation of our systems planned for the 2022-27 regulatory period. We delivered upgrades to core business systems which has improved functionality and modernised our tools, allowing for improvements in business processes and some savings in licensing costs. We are consolidating platforms and data warehouses to reduce support requirements and deliver greater efficiency.

[92] A hard insurance market is characterised by moderate to high premium increases, more selective underwriting and greater due diligence by insurers and a reduction in capacity and cover.

5.3.3.6 In-Vehicle Asset Management Systems

We have progressed the installation of In-Vehicle Asset Management Systems (IVAMS) across our vehicle fleet as part of a project to improve our operational vehicle resource utilisation, improve safety and refine maintenance schedules. These systems are not yet fully operational while we continue consultation with our employees, hence the benefits associated with this system have not been realised.

5.3.3.7 Value driven maintenance

Powerlink takes a value driven maintenance approach to deliver cost-effective outcomes, while meeting our obligations to provide safe and reliable and cost effective prescribed transmission services to our customers. We have identified opportunities to improve and deliver greater value by changing the frequency of selected maintenance activities and removing some annual activities in favour of a risk-based program.

5.3.3.8 Other productivity initiatives

In addition to the productivity initiatives in our 2023-27 Revenue Proposal, we have realised benefits from other initiatives implemented in the current 2022-27 regulatory period. The implementation of Microsoft Copilot has boosted productivity through the automation of repetitive tasks, the ability to quickly research, analyse and interpret large datasets and streamline communication. Other initiatives included the commencement of a Christmas closure period and the option to cash out leave.

5.3.4 Benchmarking performance

5.3.4.1 Regulatory requirements

The Rules[93] require the AER to prepare and publish an annual benchmarking report that describes the relative efficiency of each TNSP. The AER must have regard to the most recent annual benchmarking report when assessing whether operating expenditure forecasts provided by a TNSP within its Revenue Proposal represent efficient expenditure[94].

5.3.4.2 Our approach

We considered benchmarking in the calculation of the trend parameter of our operating expenditure ‘base-trend-step’ model. This includes consideration of our benchmarking results and industry-wide productivity trends.

The AER focuses on multilateral productivity measures in its annual benchmarking report for TNSPs. This measures how efficiently a business transforms a ‘basket’ of physical and financial inputs into a ‘basket’ of outputs. Inputs to the AER’s benchmarking model for transmission include physical inputs, such as the capacity of the network, as well as financial inputs, such as operating expenditure. It is not solely related to the cost to customers.

Economic benchmarking of electricity transmission businesses is impacted by the small number of TNSPs in Australia and their specific operating environments. The AER acknowledges this limitation in applying its benchmarks to TNSPs[95], while its consultant, Quantonomics, specifically recognises that not all external factors arising from a TNSP’s operating environment can be captured in the benchmark models[96].

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[93] National Electricity Rules, clause 6A.31.
[94] National Electricity Rules, clause 6A.6.6(e).
95 Annual Benchmarking Report - Electricity transmission network service providers, Australian Energy Regulator, November 2024.
[96] Economic Benchmarking Results for the Australian Energy Regulator’s 2025 TNSP Annual Benchmarking Report, Quantonomics, November 2025, page 8.

Operating Environment Factors (OEFs) that may be specific to one or a subset of TNSPs, which can influence outcomes while being outside the TNSPs' control, include:

- application of different financial capitalisation policies, i.e. instances where a TNSP incorporates expenditure into operating expenditure where another would capitalise it
- differences in network terrain, that may influence expenditure necessary to maintain the network, and
- differences in the geographic nature of networks, which may mean some TNSPs need to invest in infrastructure that another TNSP would not.

Powerlink has previously expressed the need for a broader review of the economic benchmarking specification for transmission to ensure that the range of services provided is captured more effectively and reflects the new investment obligations to support the transition of the transmission system[97]. In developing this Revenue Proposal, we proposed alternative measures of output growth, which we consider to be more suitable output measures for the purposes of the rate of change and benchmarking. These measures were presented to and considered by our Revenue Proposal Reference Group (RPRG) but have not been factored into the base-trend-step approach in our Revenue Proposal (refer Section 5.6.2).

The AER recognises that substantial new investment in the transmission network is likely to be captured within the current economic benchmarking model inputs (operating and capital expenditure). However, it is less clear that this is the case for all relevant outputs. The AER has stated that it is closely monitoring developments in the transmission network environment and will consider the validity of current outputs, as well as any potential additions to the output variables, in future transmission benchmarking development work[98]. We are not yet aware of the likely timing of this development work.

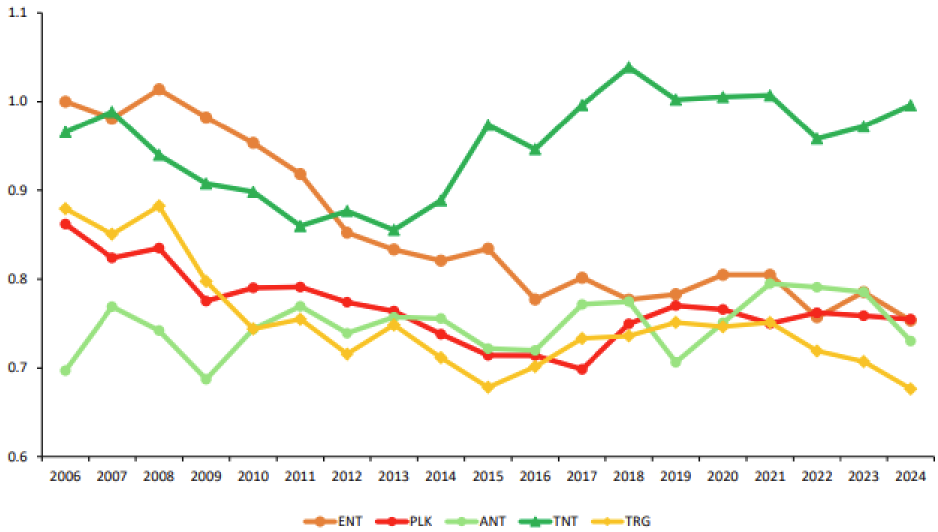
5.3.4.3 Our benchmarking performance

Our overall performance under the AER's economic benchmarking approach in its most recent 2025 TNSP Annual Benchmarking Report has decreased slightly in 2024, as shown in Figure 5.1. This is a marginal reduction on our 2018/19 outcome when our base year operating expenditure was deemed not materially inefficient by the AER.

These results are an amalgam of both operating expenditure and capital expenditure productivity performance. Powerlink is now ranked second out of five TNSPs under the Multilateral Total Factor Productivity Measure (MTFP).

[97] 2024 Annual Benchmarking Report – Electricity Transmission Network Service Providers, Australian Energy Regulator, Section 1.4.
[98] 2025 Annual Benchmarking Report – Electricity Transmission Network Service Providers, Australian Energy Regulator, Section 1.4.2.

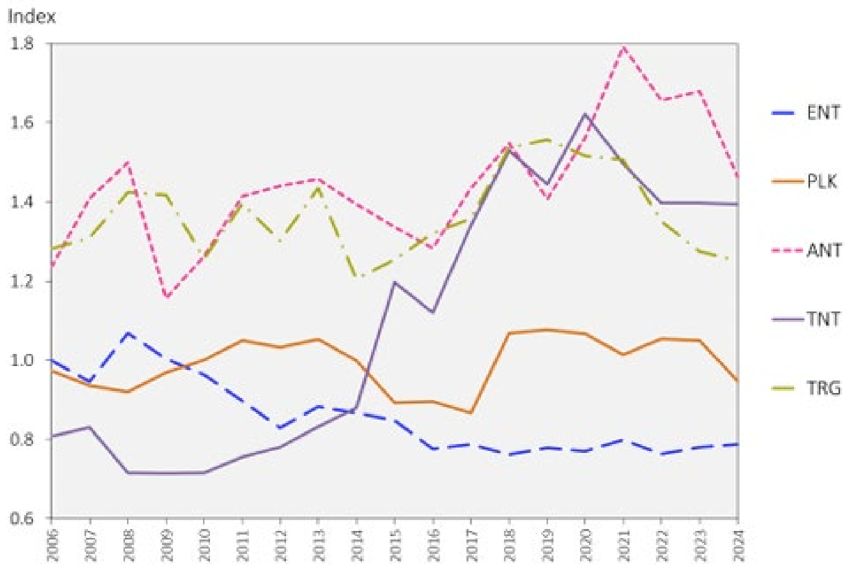
Figure 5.1 - Electricity transmission MTFP indexes by TNSP, 2006-24 (Source: AER[99])



Legend: ENT-ElectraNet, PLK-Powerlink, ANT-AusNet, TNT-TasNetworks, TRG-Transgrid

Specific to operating expenditure productivity, the AER's benchmarking analysis shows that Powerlink's operating expenditure Multilateral Partial Factor Productivity (MPFP) performance declined in 2024, broadly aligned to the industry trend of operating expenditure productivity declining, as shown for four of the five TNSPs in Figure 5.2.

Figure 5.2 - TNSP operating expenditure multilateral partial factor productivity indexes, 2006 to 2024 (Source: Quantonomics[100])



Legend: ENT-ElectraNet, PLK-Powerlink, ANT-AusNet, TNT-TasNetworks, TRG-Transgrid

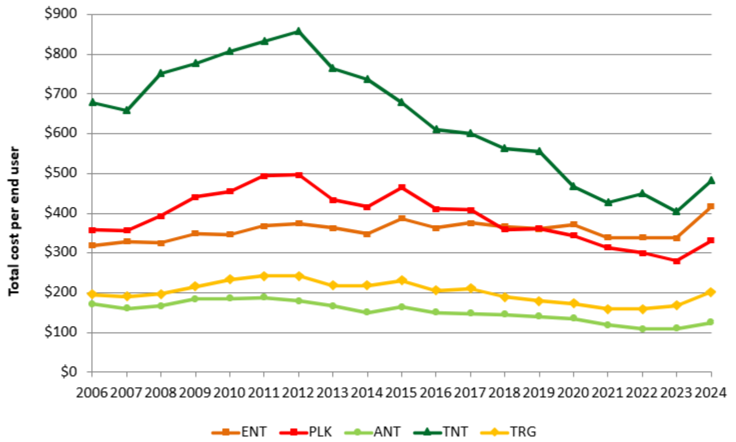
[99] Annual Benchmarking Report - Electricity transmission network service providers, Australian Energy Regulator, November 2025.
[100] Economic Benchmarking Results for the Australian Energy Regulators 2025 TNSP Annual Benchmarking Report, Quantonomics, November 2025, page 14.

In its Annual Benchmarking Report the AER also publishes Partial Productivity Indicators (PPIs) which provide a simple representation of the input costs used to produce particular outputs by TNSPs, and may be used to provide a general indication of comparative performance in delivering one type of output. These performance indicators are shown in Figure 5.3. For each of these metrics, a lower cost represents better performance.

Powerlink has experienced a decline in performance in 2024 across all measures, primarily driven by increases in expenditure as discussed in Section 5.3.2. Overall, Powerlink's total cost (incorporating capital expenditure and operating expenditure) has increased by 19.8%, compared to the industry average of 20.3%. This indicates that the cost increases experienced by Powerlink have similarly impacted the broader industry and these increases have not been influenced by the measured outputs. In most cases, Powerlink's performance has improved from 2006.

Figure 5.3 - Partial Performance Indicators (PPIs) ($2024), 2006 to 2024 (Source: AER[101])

Total cost per end user



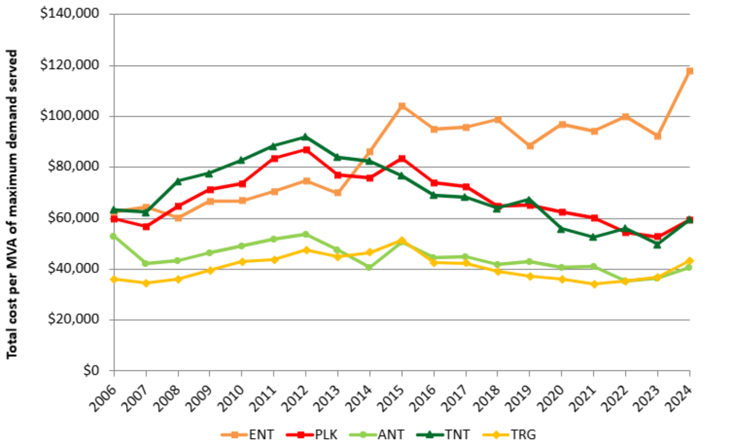
Legend: ENT-ElectraNet, PLK-Powerlink, ANT-AusNet, TNT-TasNetworks, TRG-Transgrid

Powerlink ranks third out of the five TNSPs for the total cost per end user which has increased by 18.7% from 2023 to 2024. This is slightly less than the industry average of 19.1%.

Expenditure in 2024 increased at a significantly greater rate than the number of end users for all TNSPs which increased by an average of 0.96%. For Powerlink, total cost increased by 19.8% compared to an increase in end users of 0.91%.

Total cost per user has decreased by 7.4% from 2006 to 2024.

Total cost per MVA of maximum demand served



Legend: ENT-ElectraNet, PLK-Powerlink, ANT-AusNet, TNT-TasNetworks, TRG-Transgrid

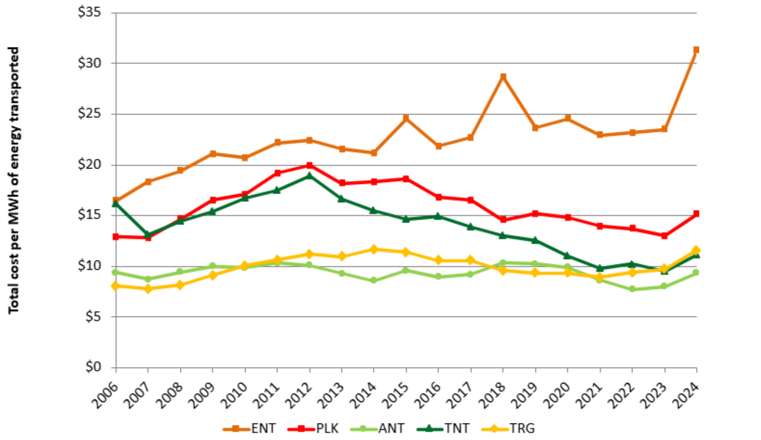
Powerlink ranks third out of the five TNSPs for the total cost per MVA of maximum demand which increased by 12.6% from 2023 to 2024. This is less than the industry average increase of 17.7%.

Expenditure in 2024 increased at a significantly greater rate than the maximum demand for all TNSPs which increased by an average of 2.33%. For Powerlink, total cost increased by 19.8% compared to an increase in end users of 6.36%.

Total cost per MVA of maximum demand decreased by 0.4% from 2006 to 2024.

101 AER – 2025 Partial Performance Indicators for transmission, Australian Energy Regulator, November 2025

Total cost per MWh of energy transported



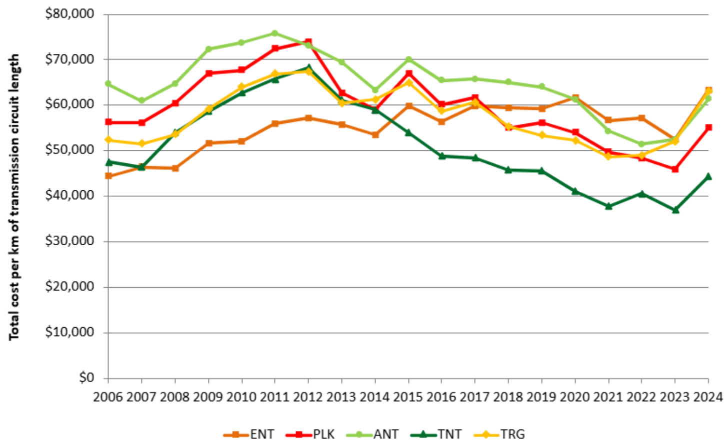
Legend: ENT-ElectraNet, PLK-Powerlink, ANT-AusNet, TNT-TasNetworks, TRG-Transgrid

Powerlink ranks fourth out of the five TNSPs for the total cost per MWh of energy transported which increased by 16.4% from 2023 to 2024. This is less than the industry average of 20.6%.

Expenditure in 2024 increased at a significantly greater rate than the energy transported for all TNSPs which decreased by an average of 0.08%. For Powerlink, total cost increased by 19.8% compared to an increase in end users of 2.96%.

Total cost per MWh of energy transported increased by 17.6% from 2006 to 2024.

Total cost per km of transmission circuit length



Legend: ENT-ElectraNet, PLK-Powerlink, ANT-AusNet, TNT-TasNetworks, TRG-Transgrid

Powerlink ranks second out of the five TNSPs for the total cost per circuit km which increased by 19.8% from 2023 to 2024. This is the same as the industry average.

Expenditure in 2024 increased at a significantly greater rate than the circuit length for all TNSPs which increased by an average of 0.43%. For Powerlink, total cost increased by 19.8% compared to an increase in end users of 0.03%.

Total cost per circuit km decreased by 2.2% from 2006 to 2024.

5.3.4.4 Independent assessment of performance

We engaged HoustonKemp to provide an independent review of our relative performance based on available and forecast information, and to advise on the potential efficiency of our proposed base year (2025/26) to forecast operating expenditure in the 2027-32 regulatory period. The key elements of that review are focused on:

- Multilateral Total Factor Productivity (MTFP)
- Capital expenditure Multilateral Partial Factor Productivity (capital expenditure MPFP), and
- Operating expenditure Multilateral Partial Factor Productivity (operating expenditure MPFP).

Based on actual results for 2023/24 and 2024/25 and the current forecast for 2025/26, Powerlink's operating expenditure performance is expected to decline due to an increase in cost, with no corresponding increase in output. The outcome for 2023/24 is aligned with the industry trend, with only one TNSP (ElectraNet) displaying an improvement in operating expenditure MPFP for that year.

The AER has not yet published comparative TNSP data for 2024/25 and 2025/26. As a result, we expect to provide comparative data from the Annual Information Order returns for 2024/25 in our Revised Revenue Proposal.

HoustonKemp's key findings on our operating expenditure performance, particularly as they relate to our proposed operating expenditure base year (2025/26), is summarised in Section 5.6.1.

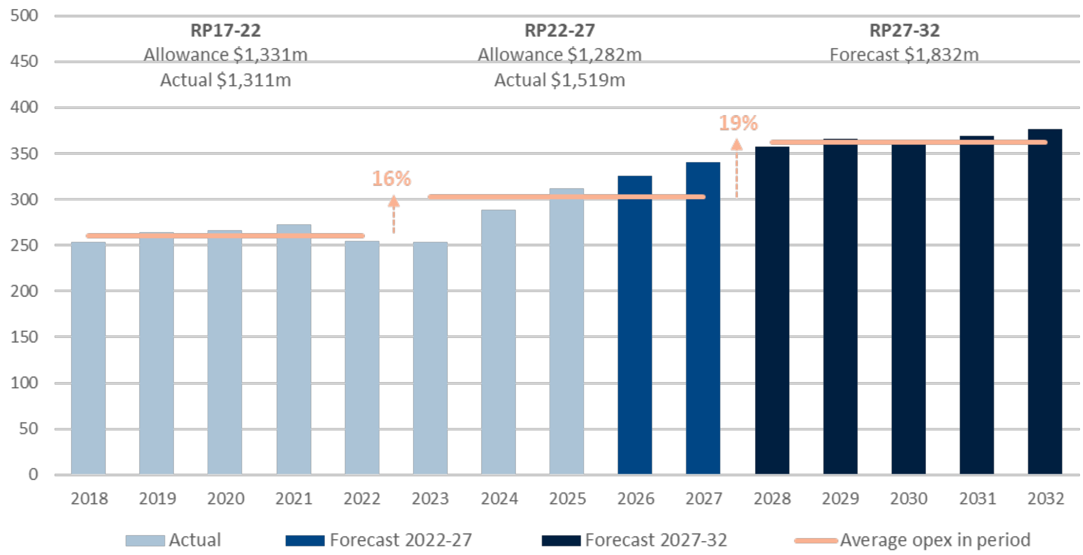
5.4 Forecast Operating Expenditure

Our Expenditure Forecasting Methodology (included as Appendix 4.03) discusses our approach to forecasting operating expenditure, which Powerlink sought RPRG input on prior to lodging with the AER in June 2025. We have made one change to the proposed methodology relating to the approach for forecasting our insurance costs. This is discussed in Section 5.5. Our operating expenditure forecasting methodology is designed to produce forecasts that satisfy the requirements of the Rules[102] including the operating expenditure objectives in Section 5.5.1 and the operating expenditure criteria and factors in Appendix 4.01. It will allow us to maintain and operate the network safely, meet the expected demand for prescribed transmission services and comply with all applicable regulatory obligations and requirements. In formulating our operating expenditure forecast, we have also considered the AER's 2024 Expenditure Forecast Assessment Guideline for Electricity Transmission[103] and Better Resets Handbook[104].

5.4.1 Total forecast operating expenditure

Our total forecast operating expenditure for the 2027-32 regulatory period, along with our actual/forecast expenditure for the previous and current regulatory periods, is shown in Figure 5.4.

Figure 5.4 - Total actual historical and forecast operating expenditure ($million real, 2026/27)



Our total forecast operating expenditure is $1,810.2 million (excluding debt raising costs). This represents a $293.0 million (19%) increase from actual/forecast operating expenditure for the 2022-27 regulatory period. With debt raising costs included, our total forecast operating expenditure is $1,832.2 million, a $313.6 million (21%)

102 National Electricity Rules, clause 6A.6.6.
103 Expenditure Forecast Assessment Guideline for Electricity Transmission, Australian Energy Regulator, October 2024.
104 Better Resets Handbook – Towards Consumer Centric Network Proposals, Australian Energy Regulator, July 2024.

increase from actual/forecast operating expenditure in the 2022-27 regulatory period. To derive this forecast, we have applied the AER's base-trend-step approach.

We have proposed 2025/26 (year 4 of the current regulatory period) as our efficient base year. We have reviewed our expenditure in this year on a category basis and have had the efficiency of this base year independently assessed (refer Section 5.6.1).

We applied an annual rate of change to our base year which broadly reflects the change in output growth, price growth and productivity growth. Our approach to the rate of change calculation and the resulting rates is discussed further in Section 5.6.2, including an alternative approach to output growth which we considered but did not adopt in our Revenue Proposal.

We have included step changes for material new costs that we will incur that are not in our base year operating expenditure. These are discussed further in Section 5.6.3 in summary, to:

- uplift physical security, associated with meeting our obligations as a critical infrastructure provider under the *Security of Critical Infrastructure Act 2018 (SOCI Act)*
- transition to cloud-based computing solutions, in line with industry trends, and the appropriate accounting treatment for those costs, with an associated reduction in capital expenditure, and
- enhance overnight network monitoring, by addressing sole overnight control room operator risk, as supported by AEMO.

We have provided category specific forecasts for the AEMO participant and cyber security fees, network support and debt raising costs (refer Section 5.10). Our forecast expenditure by category is shown in Table 5.3.

Table 5.3 - Forecast operating expenditure by category ($million real, 2026/27)

Operating expenditure category	2028	2029	2030	2031	2032	Total
Controllable operating expenditure						
Field maintenance	116.9	117.9	119.3	121.2	123.5	**598.9**
Operational refurbishment	42.7	43.1	43.6	44.3	45.1	**218.7**
Maintenance support	33.5	33.8	34.1	34.6	35.2	**171.2**
Network operations	38.6	39.0	39.4	40.0	40.7	**197.7**
Asset management support	41.4	41.8	42.3	43.0	43.8	**212.4**
Corporate support	47.3	53.1	47.2	47.1	48.6	**243.3**
Total controllable operating expenditure	**320.4**	**328.6**	**326.0**	**330.1**	**337.1**	**1,642.2**
Other operating expenditure						
Insurance premiums	9.2	9.3	9.4	9.5	9.7	**47.1**
Self-insurance	2.0	2.0	2.0	2.0	2.1	**10.1**
Network support (1)	-	-	-	-	-	**-**
AEMC levy	6.0	6.1	6.1	6.2	6.4	**30.8**
AEMO participant and cyber security fees	15.0	15.5	16.0	16.5	17.0	**80.1**
Debt raising costs	4.3	4.4	4.4	4.4	4.5	**22.0**
Total other operating expenditure	**36.5**	**37.2**	**37.9**	**38.7**	**39.7**	**190.0**
TOTAL OPERATING EXPENDITURE	**356.9**	**365.8**	**363.9**	**368.9**	**376.7**	**1,832.2**
TOTAL OPERATING EXPENDITURE (excl. debt raising costs)	**352.6**	**361.4**	**359.5**	**364.5**	**372.2**	**1,810.2**

(1) Network support incorporates both system security network support payments and network alternative support payments. From 1 December 2024, system security network support payments were recovered as a direct pass through via prescribed transmission prices. We forecast $0 for network support costs.

5.4.2 Operating expenditure objectives

We consider that our forecast operating expenditure achieves the operating expenditure objectives set out in the Rules. This is summarised in Table 5.4 and discussed in detail in Appendix 4.01 Operating and Capital Expenditure Criteria and Factors.

Table 5.4 - How we meet the operating expenditure objectives

Operating expenditure objective	How our proposal meets this objective
Meet or manage the expected demand for prescribed transmission services over the period	Maximum demand is forecast to gradually increase over the 2027-32 regulatory period, while minimum demand is forecast to decline. Our operating expenditure reflects a prudent and reasonable cost forecast to operate and maintain our transmission network and deliver safe and reliable supply in an increasingly complex operating environment.
Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services	We are subject to regulatory obligations as the holder of a Transmission Authority under the *Electricity Act 1994 (Qld)* and as a registered TNSP in the National Electricity Market (NEM). As a corporation, we are also subject to various other environmental, cultural heritage, planning, Workplace Health & Safety, industrial, financial and other regulations. Our compliance with these regulatory obligations and requirements is encompassed in our Strategic Asset Management Plan and associated policies and procedures, which provide the foundation for our operating and maintenance activities. New regulatory obligations and other requirements have also been assessed to determine the potential effect on forecast operating expenditure in the 2027-32 regulatory period. We have included three step changes in this Revenue Proposal to address these requirements.
Maintain the quality, reliability and security of supply of prescribed transmission services and maintain the safety, reliability and security of the transmission system through the supply of prescribed transmission services	Our operating expenditure forecast includes prudent provision to maintain the safety of the transmission system and deliver reliable services to our customers. An appropriate balance of operating and capital expenditure has been proposed in our 2027-32 Revenue Proposal to ensure network assets deliver the required safety, reliability, availability and quality of supply in a prudent and efficient manner.
Contribute to achieving emissions reduction targets through the supply of prescribed transmission services	Powerlink plays a pivotal role in Queensland's energy transition through its transmission infrastructure. As Queensland's System Strength Service Provider, Powerlink is investing in synchronous condensers to address system strength requirements to maintain fault levels and support voltage stability for new inverter-based resources. We have not included costs associated with maintaining these synchronous condensers in our forecast as they do not form part of this regulatory process[105].

[105] Powerlink intends to lodge a Contingent Project Application with the AER for the capital expenditure in the 2022-27 and 2027-32 regulatory periods for the installation of synchronous condensers and the resulting incremental operating expenditure for the 2027-32 regulatory period.

5.4.3 Changes from the draft Revenue Proposal

Our draft Revenue Proposal included total forecast operating expenditure of $1,805.5 million ($ real, 2026/27), excluding debt raising costs. Since publishing our draft Revenue Proposal in September 2025, we have made several changes that have not had a material impact to our total forecast operating expenditure overall. These include:

- reflecting the latest inflation data, as published by the Reserve Bank of Australia (RBA) in November 2025
- refining our proposed step changes, including the removal of the synchronous condenser maintenance step change
- updating our circuit kilometres, based on Annual Information Order return data for 2024/25 and revised project timings
- updating the rate of change calculations to align with the revised output weightings and productivity factors reflected in the AER's latest benchmarking report released in November 2025
- changing the approach for forecasting insurance costs from category specific to trend-based, and
- updating to the AEMO participant and cyber security fees, based on the latest information provided by AEMO in December 2025.

Table 5.5 summarises the difference in total forecast operating expenditure between our draft Revenue Proposal (September 2025) and our Revenue Proposal.

Table 5.5 - Forecast operating expenditure comparison ($million real, 2026/27)

	2028	2029	2030	2031	2032	Total
Draft Revenue Proposal (1)	348.4	353.8	357.0	363.2	383.0	**1,805.5**
Revenue Proposal (2)	352.6	361.4	359.5	364.5	372.2	**1,810.2**
Difference	4.2	7.6	2.5	1.2	10.8	**4.8**
Difference (%)	1.2%	2.1%	0.7%	0.3%	(2.8%)	**0.3%**

(1) Excludes debt raising costs.
(2) Reflects underlying operating expenditure, excluding movements in provisions and debt raising costs.

5.5 Operating expenditure forecasting methodology

Our Expenditure Forecasting Methodology (included as Appendix 4.03) discusses the approach to forecasting our operating expenditure, which Powerlink sought RPRG input on prior to lodging with the AER in June 2025. We have based our approach on the AER's 2024 Expenditure Forecast Assessment Guideline for Electricity Transmission[106] and Better Resets Handbook[107].

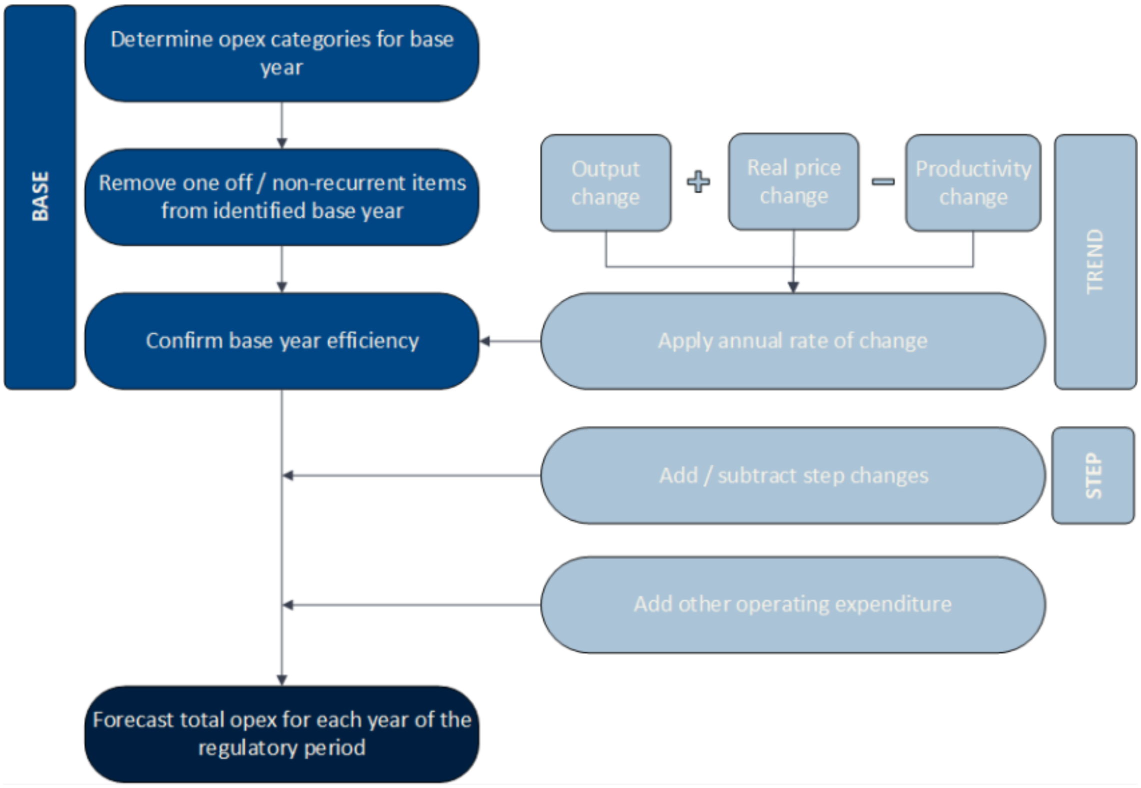
Our forecasting approach is consistent with our Expenditure Forecasting Methodology submitted to the AER in June 2025, except for the proposed category specific forecasts. We noted in our Expenditure Forecasting Methodology that we intended to include a category specific forecast for our insurance costs. Based on the forecasts received from our insurance broker and discussions with the RPRG, we have now decided to include these costs as part of the base-trend-step forecast. This is discussed further in Section 5.7.1.

[106] Expenditure Forecast Assessment Guideline for Electricity Transmission, Australian Energy Regulator, October 2024.
[107] Better Resets Handbook – Towards Consumer Centric Network Proposals, Australian Energy Regulator, July 2024.

We also proposed to review the appropriateness of the output measures. We engaged with the RPRG on this in July and September 2025 and empowered the RPRG (under the International Association for Public Participation Public Participation Spectrum) to select the approach to be to be included in Powerlink's 2027-32 Revenue Proposal. Based on the outcome of this engagement, Powerlink adopted the AER's preferred approach to the output growth. We have provided more detail on this in Section 5.6.2.

The methodology used to prepare our operating expenditure forecast is summarised in Figure 5.5 and explained in the following sections. Further information on our approach is provided in Appendix 5.02.

Figure 5.5 - Powerlink's operating expenditure forecasting methodology



5.5.1 Operating expenditure categories

We have retained the same broad categories of operating expenditure from the current 2022-27 regulatory period, with the addition of one new non-controllable expenditure category, AEMO participant and cyber security fees, as outlined in Table 5.6.

Table 5.6 - Operating expenditure categories

Operating expenditure category	Definition	Prescribed transmission service
Controllable operating expenditure		
Direct operating and maintenance		
Field maintenance	Includes all field activities to ensure plant can perform its required functions. There are four types of field maintenance: routine, condition-based, emergency and deferred corrective maintenance. Field maintenance costs include all labour and materials needed to perform the required maintenance tasks. Each field maintenance type is further separated into five major asset type categories: substations, transmission lines, secondary systems, communications and vegetation.	Exit, entry, Transmission Use of System (TUOS) and common services
Operational refurbishment	Involves activities that return an asset to its pre-existing condition or function, or activities undertaken on specific parts of an asset to return these parts to their pre-existing condition or function. These refurbishment activities do not involve increasing the capacity or capability of the plant or extending its life beyond its original design.	Exit, entry, TUOS and common services
Maintenance support	Includes activities where maintenance service providers undertake asset support functions in the field as well as non-field functions supporting maintenance functions for the operate/maintain phase of the asset life cycle. Examples of activities include maintenance procedure development, performance management and maintenance auditing. This category also includes local government rates charges, water charges, electricity charges and charges for permits and licencing for Powerlink.	Exit, entry, TUOS and common services
Network operations	Includes control centre functions as well as those additional activities required to ensure the safe, secure, reliable and efficient operational management of the Queensland transmission network. Network operations also includes other control room activity not related to Powerlink assets such as switching to allow access to customer assets, new connections and AEMO Requirements.	Exit, entry, TUOS and common services
Other controllable expenditure		
Asset management support	Activities required to support the strategic analysis, development and ongoing asset management of the network. There are four major sub elements: network planning, business development, regulatory management and operations.	Exit, entry, TUOS and common services
Corporate support	Corporate support encompasses the support activities required by Powerlink to ensure adequate and effective corporate governance. This includes corporate and direct corporate support charges and also revenue reset costs.	Common services
Non-controllable operating expenditure		
Other operating expenditure		
Insurances	This covers insurance premiums for Powerlink's network and non-network assets and a self-insurance allowance to provide cover for losses that cannot be insured.	Common services

Operating expenditure category	Definition	Prescribed transmission service
Network support	Network support refers to costs associated with non-network solutions used by Powerlink as a cost-effective alternative to network investment. These costs can be for various services including inertia provision, system strength and other network support services.	TUOS services
AEMC levy	Since 2014/15, the *Electricity Act 1994 (Qld)* has required electricity transmission networks in Queensland to pay a share of the State's cost to fund the AEMC.	Common services
AEMO participant and cyber security fees	The AEMO participant fee is a charge imposed by AEMO to recover its efficient associated with performing core National Electricity Market (NEM) functions. It applies to all registered participants, including TNSPs. The AEMO cyber security fee is a charge introduced to recover the efficient costs of fulfilling its expanded cyber security responsibilities under the Rules.	Common services
Debt raising costs	Debt raising costs relate to costs incurred by an entity over and above the debt margin.	Common services

5.6 Application of the base-trend-step methodology

This section outlines how we have applied the AER's base-trend-step methodology to forecast our operating expenditure, and the inputs and assumptions used for each element. This approach consists of the following:

- determine an efficient base year from which to forecast operating expenditure (Section 5.6.1.1)
- establish an annual rate of change to trend forecast operating expenditure (Section 5.6.2)
- assess step changes in operating expenditure (Section 5.6.3), and
- add other category specific operating expenditure (Section 5.7).

5.6.1 Efficient base year

5.6.1.1 Base year selection

We proposed 2025/26 (Year 4 of the current regulatory period) as the base year in our base-trend-step model. This base year has been selected as Powerlink considers that it is reflective of an efficient level of the expenditure required to meet the operating expenditure objectives[108] and criteria[109]. For this Revenue Proposal we have applied a forecast for our 2025/26 base year. For our Revised Revenue Proposal in December 2026, we will apply actual costs (or in AER terms, the revealed cost) in line with the AER's preference[110].

[108] National Electricity Rules, clause 6A.6.6(a)
[109] National Electricity Rules, clause 6A.6.6(c)
[110] Expenditure Forecast Assessment Guideline for Electricity Transmission, Australian Energy Regulator, October 2024.

We considered the use of 2024/25 as a potential base year from which to forecast operating expenditure for the next regulatory period, as it represents the latest year of audited accounts prior to lodging our Revenue Proposal. However, we do not consider this to be a typical year of operation for the following reasons:

- there are new regulatory and compliance costs that we will incur to meet our SOCI Act obligations, maintain the required Security Profile maturity level for cyber security and address arc flash electrical safety risks that are not revealed in 2024/25, and
- the volume of maintenance work undertaken was lower than required ongoing levels with both routine and non-routine maintenance activities impacted by restricted access to numerous sites across the network.

We engaged on our proposed base year with the RPRG in the development of our Revenue Proposal and determined that 2025/26 is the most appropriate choice for our base year operating expenditure. We engaged HoustonKemp to undertake an independent review of the efficiency of our 2025/26 operating expenditure and our performance against other TNSPs. This is discussed further in this section and HoustonKemp's report is provided in Appendix 5.03.

5.6.1.2 Base year adjustments

We reviewed forecast expenditure in the base year for non-recurrent items or items that are not considered to reflect an efficient level of recurrent operating expenditure. We adjusted for a portion of Operational Technology (OT) licences that will not continue after 2025/26 and made an adjustment for the costs associated with the preparation of the Revenue Proposal which do not occur to the same extent in each year of the regulatory period.

Our approach to remove this expenditure is consistent with the AER's 2024 Expenditure Forecast Assessment Guideline. We will refine our base year adjustments to align with revealed costs in our Revised Revenue Proposal. We outline these adjustments and the resultant base year expenditure in Table 5.7.

Table 5.7 - Adjusted expenditure items in the 2025/26 base year ($million real, 2026/27)

Operating expenditure category	Total
2025/26 unadjusted base year operating expenditure (controllable expenditure, insurances and AEMC levy)	325.1
Adjustment for Operational Technology Licences not continuing	(0.3)
Adjustment for Revenue Reset preparation	(6.0)
2025/26 base year operating expenditure – efficient base year	**318.8**

The unadjusted base year has increased from our draft Revenue Proposal due to the change in forecasting approach for insurance costs. These were previously excluded from the base year as we had taken a category specific forecasting approach for this category.

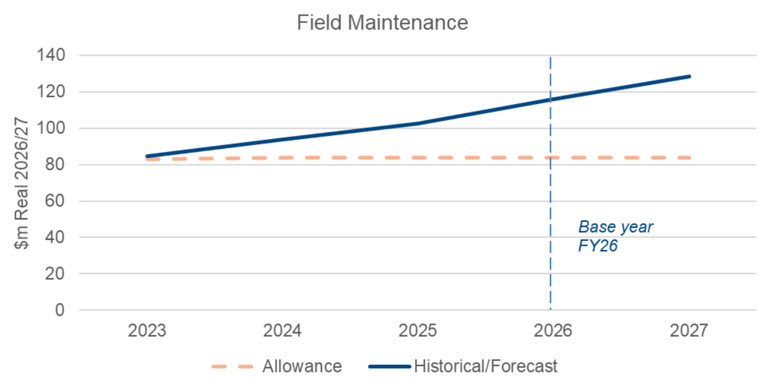
Operating expenditure associated with the AEMO participant and cyber security fees, network support and debt raising costs is not included in the base year, as we have taken a category specific approach to forecast these items (refer Section 5.7).

5.6.1.3 Category analysis of operating expenditure

To confirm the reasonableness of our selected base year, we assessed the relative performance of each major category of operating expenditure for the current 2022-27 regulatory period which has been trended under the base-trend-step methodology. This includes all controllable expenditure categories and the insurance and AEMC levy categories. Other non-controllable expenses have been forecast as category specific items using a zero-based approach and therefore were not assessed.

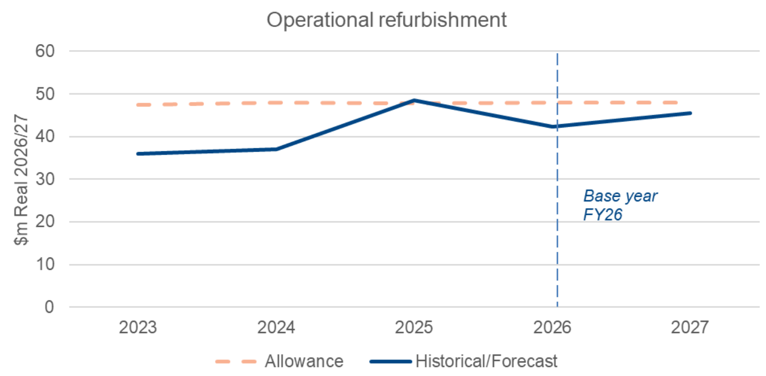
The results of this analysis, shown in Figure 5.6, highlights that at a category level, the proposed 2025/26 base year is more reflective of the ongoing costs required to maintain and operate the network.

Figure 5.6 - Category analysis of operating expenditure ($million real, 2026/27)

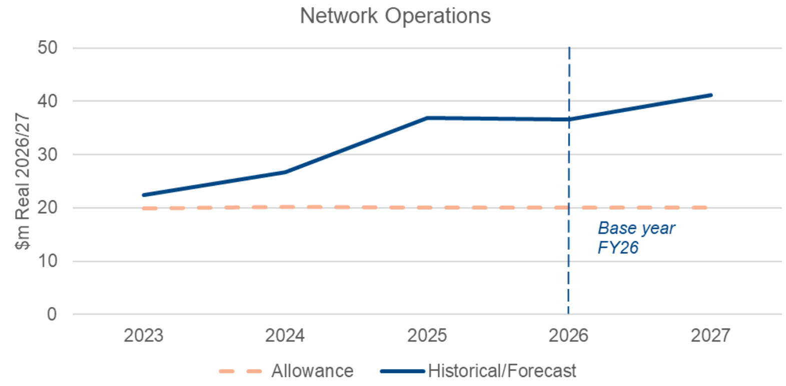


Maintenance in 2025 was disrupted by limited access to 24 substations due to a safety concern related to current transformers, and the response to Tropical Cyclone Alfred. This led to the cancellation and rescheduling of some maintenance work, such that the volume was below ongoing required volumes. The 2026 forecast reflects maintenance volumes aligned with expected needs during the upcoming regulatory period.

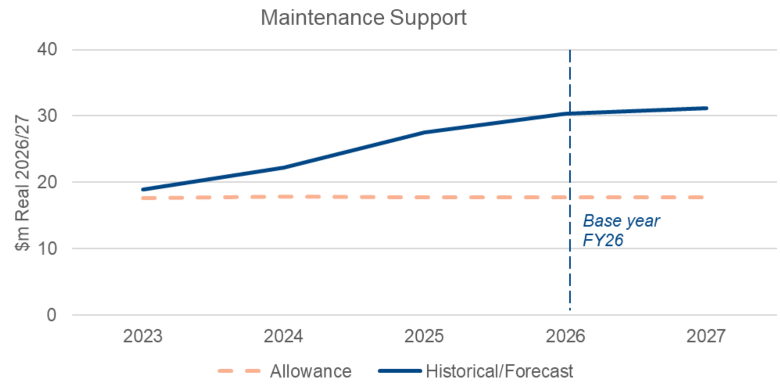
From 2026 we have forecast the full cost of compliance with new electrical safety obligations addressing arc flash risk near energised equipment, effective from January 2025.



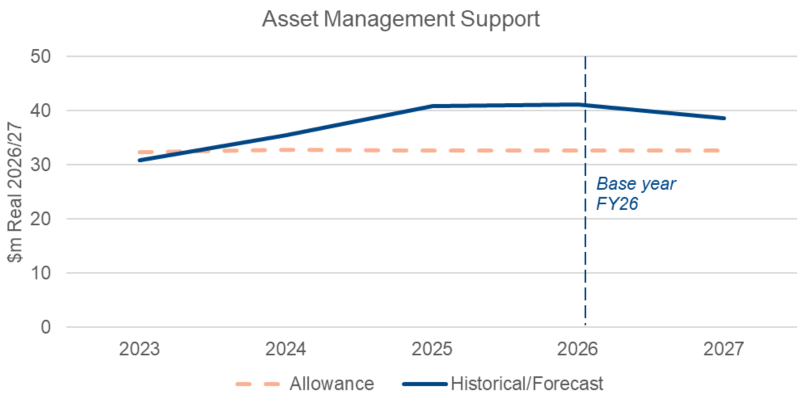
The ongoing insulator replacement program forms the core of the refurbishment expenditure. This is forecast to continue at a consistent level for the next regulatory period. Expenditure in 2025 was higher than planned due to the inclusion of a significant refurbishment project.



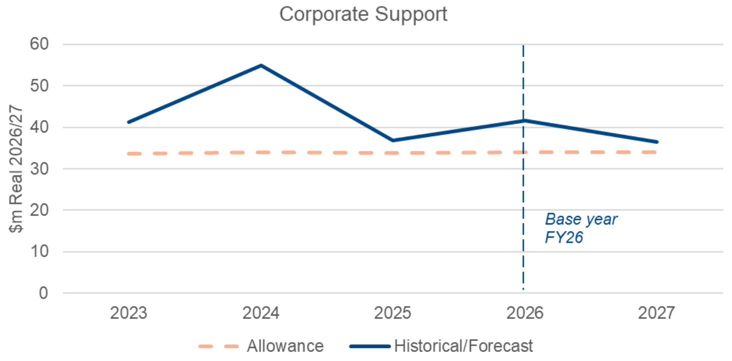
As the transmission system evolves and complexity increases, so does the effort required to maintain safe and reliable transmission operations. There are increasing requirements for more engineering studies, alarm responses, simulations, contingency planning and network support.



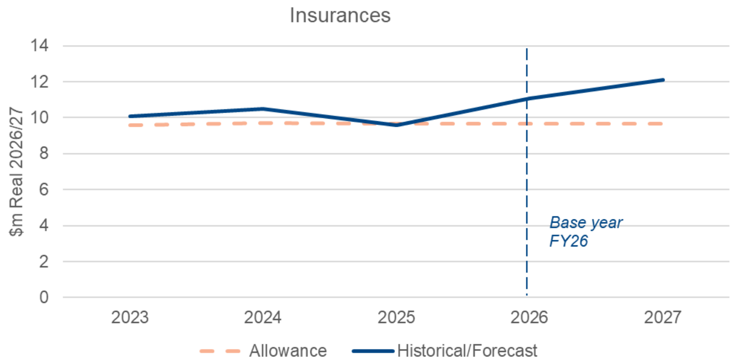
Expenditure in 2026 reflects ongoing recurrent costs, with additional spend driven by changes to management of electrical authorisations and investigations into plant condition and failures. A base year adjustment is proposed to account for changes in OT licensing.



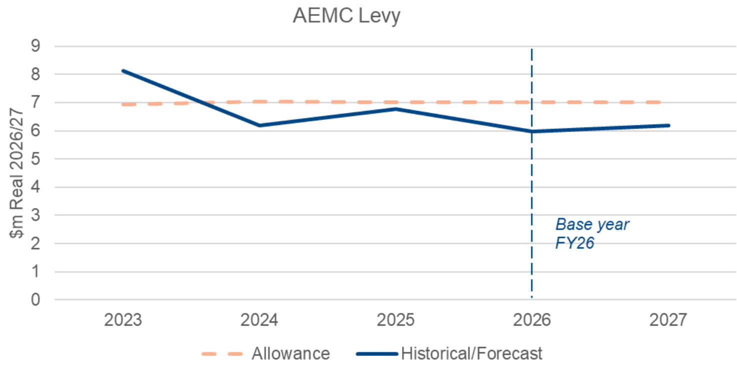
Expenditure increases in 2026 reflect strategic planning for the future network, including network simulation tools, operating schemes, system restart and contingency plans and managing voltage fluctuations. We consider these costs are representative of ongoing requirements in this category.



Expenditure in 2026 reflects ongoing IT support and licensing costs and expenditure related to maintaining our cyber security maturity level of SP-2 under AESCSF[111]. We have commenced uplifting our management of physical security to meet obligations under the SOCI Act in 2026, with further improvements required in the 2027-32 regulatory period. The base year has been adjusted to exclude non-recurrent costs of preparing our Revenue Proposal.



Combined insurance and self-insurance expenditure in 2026 reflects forecast insurance expenditure for 2027-32 regulatory period, based on independent expert advice.



Expenditure in 2026 reflects the expected ongoing AEMC levy for the 2027-32 regulatory period, based on a forecast provided by Queensland Treasury. We consider this represents efficient recurrent operating expenditure within Powerlink's base year.

5.6.1.4 Benchmarking of base year

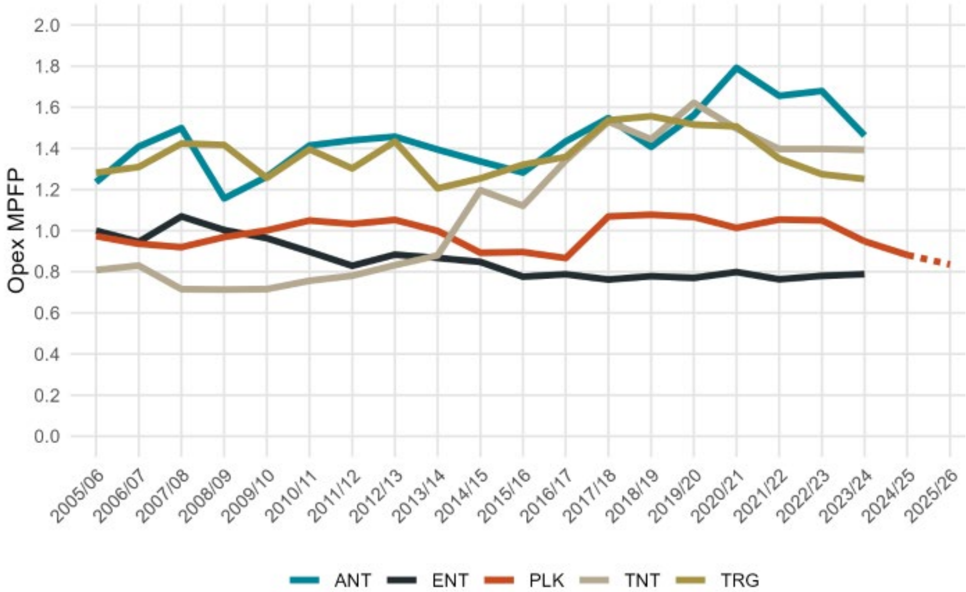
This section provides detail about our benchmarking outcomes relative to our proposed 2025/26 base year. Further information about our historical benchmarking performance is included in Section 5.4.

[111] The Australian Energy Sector Cyber Security Framework (AESCSF) is a cyber security framework developed for the Australian energy sector that leverages recognised industry frameworks and references global best-practice control standards.

Benchmarking plays a role in the AER's assessment of TNSP performance and expenditure forecasts, particularly with respect to base year operating expenditure efficiency and trends. Economic benchmarking of electricity transmission businesses is impacted by the small number of TNSPs in Australia (five) and their specific operating environments. The AER acknowledges this limitation in applying its benchmarks to TNSPs, while its consultant, Quantonomics, specifically recognises that not all external factors arising from a TNSP's operating environment can be captured in the benchmark models[112].

We engaged HoustonKemp to undertake an independent review of our base year operating expenditure. As part of its review, HoustonKemp benchmarked our expenditure against other TNSPs and examined productivity trends focussing on operating expenditure MPFP, as shown in Figure 5.7. Comparative data for other TNSPs is currently only available to the 2023/24 financial year.

Figure 5.7 - Historical and projected absolute opex MPFP by TNSP (Source: HoustonKemp)



Legend: ENT-ElectraNet, PLK-Powerlink, ANT-AusNet, TNT-TasNetworks, TRG-Transgrid

Key findings in HoustonKemp's December 2025 report[113] (included as Appendix 5.03) were:

- Powerlink's operating expenditure efficiency has declined in 2023/24 and is forecast to continue to decline in 2024/25 and 2025/26 due to increases in operating expenditure
- the decline in 2023/24 reflects the broader industry trend
- comparative data from other TNSPs is not available at this time to determine whether Powerlink's decline in operating expenditure efficiency in 2024/25 and forecast decline in 2025/26 continues to reflect the broader industry trend, and
- TNSP performance in 2024/25 is likely to provide a good indication of whether or not this is the case.

[112] Economic Benchmarking Results for the Australian Energy Regulator's 2025 TNSP Annual Benchmarking Report, Quantonomics, November 2025, page 8.
[113] Efficiency of Powerlink's proposed base year operating expenditure (2027-32), HoustonKemp Economists, December 2025.

HoustonKemp notes[114]:

> *In the absence of further evidence regarding broader industry trends, Powerlink's current benchmarking results are not yet sufficient to support a conclusion that its (forecast) 2025/26 opex is not materially inefficient.*

Powerlink anticipates that industry data to the 2024/25 financial year will be available in early 2026. This will enable HoustonKemp to undertake a comparison against the industry trend in recent years and will further inform their assessment of our base year efficiency. HoustonKemp will provide a revised report to Powerlink following the release of this data.

Powerlink considers that the benchmarking approach, which provides historical context, does not reflect the rapid change in the operating environment experienced by Powerlink and other network businesses in recent years. This was acknowledged by the AER in its most recent report in November 2025 where they noted that the changing operating environment for transmission network businesses may be reflected in input costs but may not be recognised in the relevant outputs, potentially affecting the potency of the benchmarking report[115].

In developing this Revenue Proposal, we proposed alternative measures of output growth, which we consider are more suitable output measures for the purposes of the rate of change and benchmarking. These measures were presented to and considered by our RPRG who indicated their support for the alternative measures but recommended that Powerlink adopt the AER's preferred approach to output growth. We discuss the alternative measures in Section 5.6.2.3.

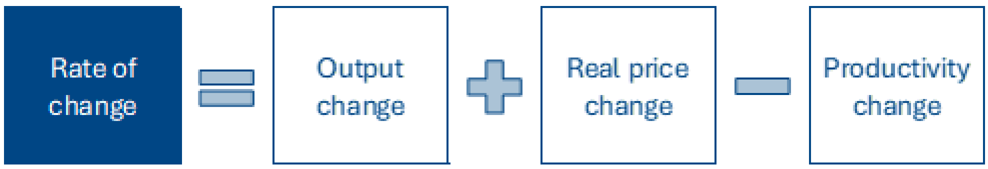
Powerlink has considered its MTFP and operating expenditure MPFP performance in the AER's most recent benchmarking report, the drivers for increased expenditure in the proposed 2025/26 base year and our ongoing engagement relating to the base year with the RPRG. We consider that the 2025/26 is the most appropriate choice for our base year operating expenditure as it represents the operating expenditure required to continue to meet the operating expenditure objectives in the next regulatory period.

5.6.2 Rate of change

5.6.2.1 Total rate of change

The overall real rate of change in the base-trend-step model is a function of the forecast change in network output, real input costs (labour and non-labour) and productivity. The calculation method for the total rate of change is shown in Figure 5.8 and is consistent with the AER's 2024 Expenditure Forecast Assessment Guideline for Electricity Transmission[116] and Better Resets Handbook[117], and our Expenditure Forecasting Methodology in Appendix 4.03.

Figure 5.8 - Forecast rate of change method



[114] Efficiency of Powerlink's proposed base year operating expenditure (2027-32), HoustonKemp Economists, December 2025, page 6.
[115] 2025 Annual Benchmarking Report – Electricity Transmission Network Service Providers, Australian Energy Regulator, November 2025, page 7.
[116] Expenditure Forecast Assessment Guideline for Electricity Transmission, Australian Energy Regulator, October 2024.
[117] Better Resets Handbook – Towards Consumer Centric Network Proposals, Australian Energy Regulator, July 2024.

Each of these components is discussed in the following sections.

Table 5.8 reflects the total rate of change applied in our Revenue Proposal for the 2027-32 regulatory period.

Table 5.8 - Total rate of change ($million real, 2026/27)

Rate of change	2028	2029	2030	2031	2032	Total
Output change	1.3	3.3	5.7	9.4	14.7	**34.4**
Price change	2.2	4.5	7.4	10.1	12.6	**36.9**
Productivity change	(1.3)	(2.7)	(4.1)	(5.4)	(6.8)	**(20.3)**
Total Rate of change	**2.3**	**5.1**	**9.0**	**14.1**	**20.5**	**51.0**

5.6.2.2 Output change

Output change is the expected growth in network output, measured by the four parameters outlined in Table 5.9. These are weighted by their assessed share of gross revenue based on weighting factors defined by the AER as part of its economic benchmarking of TNSPs[118]. We have applied the updated output index weights for non-reliability outputs as used in the AER's 2025 Annual Benchmarking Report.

Table 5.9 - Output measures

Output measure	Weighting	Description	Source
Energy throughput	9.45%	A measure of the amount of electricity that TNSPs deliver to their customers.	AEMO Electricity Statement of Opportunities (ESOO) 2025
Ratcheted maximum demand (RMD)	28.69%	TNSPs endeavour to meet the demand for energy from their customers when that demand is greatest. RMD recognises the higher maximum demand that the TNSP has had to meet in the time period examined.	AEMO ESOO 2025
Number of customers	9.32%	The number of end users is a proxy for the complexity of the TNSPs network.	Number of customers from Ergon Energy and Energex 2025-30 Revenue Proposals, trended forward for the 2031 and 2032 years, plus Powerlink direct connect customers.
Circuit length	52.54%	Reflects the distances over which TNSPs transport electricity and is a significant driver of the services a TNSP must provide.	Powerlink's Enterprise Resource Planning database (SAP) Plant Maintenance Module. Powerlink has forecast a small net increase in circuit length over the 2027-32 regulatory period

The measures used in our Revenue Proposal and their respective growth rates and data sources are detailed in Table 5.10. The last two years of the current regulatory period are shown for comparison purposes.

118 Annual Benchmarking Report 2025- Electricity Transmission Network Service Providers, Australian Energy Regulator, November 2025.

Table 5.10 - Output growth rates (% per annum)

Output measure(1)	2026	2027	2028	2029	2030	2031	2032
Energy throughput (GWh)	0.10	0.28	0.30	0.76	1.96	3.56	4.91
Ratcheted maximum demand (RMD)	4.21	0.84	1.04	1.51	1.64	2.42	3.56
Number of customers	1.09	1.06	1.05	1.03	1.01	1.04	1.01
Circuit length	0.00	0.00	0.00	0.00	0.00	0.01	0.05

(1) Output measures have been updated with the most current data available at the time of submission of our Revenue Proposal.

5.6.2.3 Alternative output change

Powerlink considers that an alternative output measure may better represent the increasing complexity experienced by TNSPs in the current environment (refer Chapter 2 Operating Environment). We considered the use of alternative measures with our RPRG for this Revenue Proposal. However, we have adopted the AER's approach for output growth.

The AER's current approach assumes the number of customers connected to transmission and distribution networks represents an appropriate proxy for the complexity of operating and maintaining a safe, reliable and cost-effective transmission system.

In addition to reliability and affordability, our customers highlighted[119] that they support investment in the energy system to move to a cleaner system for future generations. Additionally, we surveyed major commercial and industrial customers, some directly connected to our network and others connected to the distribution networks, who told us that they continue to prioritise electrification and renewable energy sources.

The energy transition is already well underway and with the increasing integration of new inverter connected generation and energy storage, Powerlink is learning and adapting to the new ways the grid is being used. The future energy system will be characterised by a mix of technologies and infrastructure along the entire supply chain, which further increases complexity.

Consequently, we engaged with the RPRG in July 2025 on the potential to establish an alternative output measure which we consider better reflects the increasing complexity of providing safe, reliable and cost-effective services to customers. The RPRG supported further analysis to understand the potential impact of an alternative output measure.

As an alternative to customer numbers, we presented a measure in our draft Revenue Proposal (published in September 2025) and engaged with the RPRG on this option. This measure was intended to broadly demonstrate the change in complexity of operating the transmission network.

Based on feedback from the RPRG we undertook further analysis and identified generation capacity as a reasonable alternative to the number of customers. This measure is intended to broadly demonstrate the change in complexity as the mix and number of connected generators changes over time.

In November 2025, Powerlink presented two options to the RPRG for consideration as a proxy for complexity – customer numbers (the current approach) and generation capacity. The options presented considered potential trade-offs with proposed step changes and the impact of changes to productivity outcomes. We empowered the

[119] Queensland Household Energy Survey, April 2025.

RPRG under the IAP2 Public Participation Spectrum to select the approach to be included in our 2027-32 Revenue Proposal. The RPRG response to the options is as follows:

> *There was support for Powerlink proposing the new measure to the AER - it is better than the current metric and the impact is very small on proposed 2027-32 revenue.*
>
> *However given the AER's comments at our meeting last week, it is very unlikely the AER would approve this change as part of an individual reset – these matters are usually dealt with in a network wide review – which would be part of a review of the productivity measurement methodology; one of the reasons that the AER prefers dealing with these matters as part of a review applying to all networks is that it provides the opportunity to fully explore the alternatives – which might provide an even better alternative than the one Powerlink proposes eg while the impact on Powerlink's 2027-32 revenue is very small we don't have the data to understand what impact it might have on following reset periods or other networks – it might be material.*
>
> *Given Powerlink's desire to present a proposal that is 'capable of acceptance', even if the RPRG might support Powerlink proposing the new measure (we think it is 'capable of acceptance'), it would likely constrain the ability to meet the aim of 'capable of acceptance' by the AER.*

Consequently, Powerlink has adopted the AER's preferred approach to the output growth.

5.6.2.4 Real price change

Real price change is the forecast real change in input costs, measured for labour and non-labour[120] costs. We consider the forecast labour and non-labour price changes represent a realistic forecast of input increases over the 2027-32 regulatory period.

Our forecast of labour input price changes is based on an average of two state-level utility industry Wage Price Index (WPI) forecasts: an independent forecast developed by Oxford Economics Australia (OEA)[121], and an alternative Queensland WPI forecast[122]. Our approach is detailed in Chapter 6 Escalation Rates.

Table 5.11 presents these forecasts along with the simple average of the two forecasts that has been used in the rate of change calculations. The last two years of the current regulatory period are shown for comparison purposes. The average annual labour price change over the 2027-32 regulatory period is 1.1%.

Table 5.11 - Real labour price growth (% per annum)

Labour Price Growth	2026	2027	2028	2029	2030	2031	2032	Average 2028-32
OEA EGWWS WPI – Qld	2.8	1.2	1.3	1.4	1.6	1.6	1.3	**1.4**
Alternative Utilities WPI – Qld	0.6	1.1	0.7	0.6	0.9	0.8	0.8	**0.8**
Average	**1.7**	**1.2**	**1.0**	**1.0**	**1.3**	**1.2**	**1.1**	**1.1**

[120] Non-labour includes expenses such as materials, insurances, fees and levies, rates, leases, hardware and software contracts, equipment hire, accommodation costs and professional and other services.
[121] Labour Cost Escalation Forecasts to 2031/32 report for Powerlink, Oxford Economics Australia, October 2025.
[122] Labour price growth forecasts, Deloitte Access Economics, March 2025. This was prepared for the Australian Energy Regulator and referenced in the Final Decision for the Energex 2025-30 Revenue Proposal.

We propose a real non-labour price growth of zero in our expenditure forecasts for the 2027-32 regulatory period. Given significant increases during the current regulatory period we recognise that there is a risk with adopting this approach. However, we consider this is an appropriate balance of risk. We discuss this approach further in Chapter 6 Escalation Rates.

To develop our real price growth escalation forecasts for the 2027-32 regulatory period, we have applied weightings of labour to non-labour of 70.4 to 29.6. These weightings are consistent with the methodology used for the AER's 2025 TNSP Annual Benchmarking Report. We investigated the appropriateness of this weighting and found it is consistent with the split of labour and materials costs in our historical operating expenditure.

The measures used in our Revenue Proposal and their respective growth rates are detailed in Table 5.12.

Table 5.12 - Price growth rate (% and $million real, 2026/27)

Price Growth Rate	2028 (%)	2029 (%)	2030 (%)	2031 (%)	2032 (%)	Average (%)	Total price growth ($)
Total price growth	0.70	0.70	0.88	0.85	0.75	0.78	**36.9**

5.6.2.5 Productivity change

Productivity change measures the forecast expected productivity improvements for a network business. The AER currently applies an industry average to calculate productivity, based on operating expenditure productivity across all TNSPs, as published annually in the AER's Economic Benchmarking Report for Electricity Transmission.

Table 5.13 presents the forecast total productivity growth for the 2027-32 regulatory period in accordance with the AER specification.

Table 5.13 - Productivity growth rate (% and $million real, 2026/27)

Productivity growth	2028 (%)	2029 (%)	2030 (%)	2031 (%)	2032 (%)	Average (%)	Total productivity growth ($)
Productivity growth	0.42	0.42	0.42	0.42	0.42	0.42	**(20.3)**

In our Revenue Proposal, we have adopted the AER's preferred productivity growth forecast of the industry average productivity change[123] for electricity transmission. We forecast a decline in productivity based on the AER's benchmarking approach which we expect will be in line with prevailing industry outcomes.

We recognise the need to identify ways to deliver further efficiency and productivity improvements during the 2027-32 regulatory period and commit to doing this as part of business as usual operations.

We will target productivity improvement through the implementation of alternative project and asset management methods which will enhance efficiency, safety and quality control. We expect that this will include the use of robotic, drone and sensor technologies, new project and maintenance delivery methodologies and improved data, systems and analytics which will enable us to reduce time, costs and delays, improve our scheduling and optimise network maintenance and performance. We will also focus on delivering business

[123] Based on latest publicly available TNSP operating expenditure partial factor productivity 2006-2024, published with the accompanying independent report by Quantonomics (Regression-based growth rates) referenced within the AER's 2025 Annual Benchmarking Report – Electricity Transmission Network Service Providers.

improvements to streamline processes, reduce errors, increase automation and improve productivity. We explore this in more detail in Appendix 5.04.

5.6.3 Step changes

We have included three operating expenditure step changes for the 2027-32 regulatory period. This followed detailed investigation of potentially material changes in our regulatory obligations, the external market and trade-offs between capital expenditure and operating expenditure.

As part of the preparation of our Revenue Proposal, we initially identified 21 potential step changes and reviewed them against a set of criteria. The criteria included whether costs were material, had not already been realised in the base year, had a high likelihood of being realised, and/or were associated with a new legislative/regulatory obligation, a change in the external market beyond our control, and/or a trade-off between capital expenditure and operating expenditure.

We also engaged with the RPRG on our potential step changes in the development of our Revenue Proposal.

Table 5.14 outlines those potential step changes that we consider will result in an increase in costs in the 2027-32 regulatory period, for which we have pursued a regulatory expenditure allowance. In determining our step changes, we have considered costs incurred or likely during the 2025/26 base year. Accordingly, the step change requested represents the amount exceeding any recurrent costs already included in base year operating expenditure.

Table 5.14 - Step changes ($million real, 2026/27)

Name	Forecast total cost impact (2027-32)	Driver and description
Physical security uplift	16.4	Regulatory obligation. Costs associated with complying with our obligations for physical security under the SOCI Act and subsequent amendments.
Transition to cloud-based solutions	60.0	External factor. There is an ongoing market shift to cloud-based information technology (IT) solutions. The costs associated with the implementation, configuration and customisation of these solutions are generally required to be treated as operating expenditure under Australian Accounting Standards. It is expected that there would be a reduction in future IT capital expenditure.
Enhance overnight network monitoring	8.7	External factor. Costs to address AEMO concerns regarding a single overnight control room operator.

Each of these step changes are discussed in turn below.

5.6.3.1 Physical security uplift

Powerlink, as a provider of critical infrastructure, is required to comply with *Security of Critical Infrastructure Act 2018 (SOCI Act).* The SOCI Act requires that owners of critical infrastructure assets implement a risk management plan to mitigate material risks associated with cyber and information hazards, personnel hazards, supply chain hazards, and physical and natural hazards.

Powerlink has identified several initiatives to uplift physical (protective) security controls to meet our needs under these regulations. These initiatives aim to upgrade our site security, increase our specialist security capability and enhance our ability to protect our critical infrastructure.

5.6.3.2 Transition to cloud-based solutions

Powerlink's investment in its Information Technology (IT) infrastructure and software solutions includes a mix of on-premise and cloud-based services. Powerlink has identified an IT investment program for the 2027-32 period, which includes a forecast of operating expenditure for cloud-based solutions.

In April 2021, the International Accounting Standards Board clarified its definition of intangible assets[124] which led to most cloud-based services (or Software-as-a-Service (SaaS)) costs no longer meeting that definition. The International Financial Reporting Standards guidance advised that these costs should be expensed (operating expenditure) rather than capitalised (capital expenditure), shifting the previous approach in relation to cloud-based solutions.

Given the continuing maturity of SaaS offerings by leading technology companies, and the move by those companies to only offer SaaS solutions in the future, Powerlink has determined, in line with the Australian Accounting Standards, that most of the future IT investment will be treated as an operating expense rather than a capital asset.

An overview of the IT investment program for the 2027-32 period is attached in Appendix 4.06 and includes the classification for each proposed element of the program.

5.6.3.3 Enhance overnight network monitoring

The key component to address our sole control room operator risk is to transition to two system controllers on overnight shifts. This shift is driven by a combination of regulatory direction, good industry practice, incident learnings, and broader workforce and safety considerations. It is increasingly recognised as a necessary evolution in transmission network operations given the increasing complexity.

AEMO recommended increased staffing in control rooms to ensure real time system stability and rapid response to contingencies as well as for the timely coordination of increasing customer connections. These require operational coordination in real time, often within short timeframes, to align to power system security guidelines for re-securing post contingent.

Single controller operations can pose significant risks, particularly during complex or cascading events. Increasing resources allows for more effective cross-checking of decisions, reduces the likelihood of human error, supports continuous situational awareness, and helps mitigate workplace health and safety risks.

5.7 Forecast other operating expenditure

We have developed category specific forecasts for AEMO participant and cyber security fees, network support costs and debt raising costs.

Our category specific (zero-based) forecasts use an external or bottom-up cost build to estimate the total cost of a particular activity. For these expenditure items, we do not consider that a trend of base year expenditure will reasonably reflect future operating expenditure requirements.

[124] Configuration or customisation in a cloud computing arrangement (IAS 38 Intangible Assets), International Financial Reporting Standards (IFRS), 27 April 2021, pp. 1-2

In the normal course of business, we classify our insurance and AEMC levy costs as non-controllable, other operating expenditure. However, for our Revenue Proposal, we have included both insurance and AEMC levy costs in our base year and have applied the rate of change rather than a category specific forecast, consistent with the AER's preferred approach.

5.7.1 Insurance

As a business, we take a holistic approach to risk management. We propose to adopt a combination of insurance policies, self-insurance and pass through arrangements in the 2027-32 regulatory period to efficiently manage the risks associated with operating our network and deliver cost-effective outcomes for customers and Powerlink.

We engaged our insurance brokers, Marsh Pty Ltd (Marsh), to advise us on our insurance and risk management approach for the 2027-32 regulatory period. Marsh also discussed the insurance market with the RPRG in November 2025. Forecasts from Marsh can be found in Appendix 5.06 and indicate that total insurance costs[125] may increase by $4.0 million (7%) in total over the 2027-32 regulatory period compared to our total actual/forecast insurance costs for the 2022-27 regulatory period.

We noted in our Expenditure Forecasting Methodology, published in June 2025, that we intended to include a category specific forecast for our insurance costs. Based on the forecasts received from Marsh and discussions with the RPRG, we have now decided to include these costs as part of the base-trend-step forecast. The adoption of a trend-based forecast for both categories of insurance for the 2027-32 regulatory period results in $0.1 million less overall for insurance costs compared to a category specific approach.

The elements of our insurance requirements are defined in more detail in the following sections.

5.7.1.1 External insurance

A key component of our risk management strategy is the establishment and maintenance of a prudent and efficient insurance program that provides financial coverage for most of our major risk exposures. We seek advice from our insurance brokers for domestic insurance and international cover, to ensure that our insurance coverage is effective and is delivered at a competitive cost.

Table 5.15 outlines our insurance premium cost forecast, trended from the 2025/26 base year expenditure, and the forecast from Marsh. We have included the base-trend-step forecast in our operating expenditure forecast.

Table 5.15 - Insurance premiums ($million real, 2026/27)

Insurance premiums	2028	2029	2030	2031	2032	Total
Base-trend-step forecast	9.2	9.3	9.4	9.5	9.7	**47.1**
Marsh forecast	7.8	8.1	8.5	8.8	9.6	**42.8**
Variance	**1.4**	**1.2**	**0.9**	**0.7**	**0.1**	**4.3**

5.7.1.2 Self-insurance

Self-insurance costs relate to losses that are below the insurance deductible amounts contained in our insurance portfolio. We engaged Marsh to review historical levels of these losses and develop a forecast of prudent self-insurance amounts for the 2027-32 regulatory period.

[125] Forecasts from Marsh have been adjusted to reflect the costs attributable to prescribed transmission services only.

Table 5.16 outlines the self-insurance cost forecast, trended from the 2025/26 base year, and the forecast from Marsh. In this case, the Marsh forecast is considerably higher than the base-trend-step forecast largely due to the inclusion of an additional self-insurance allowance to provide for the anticipated increase in towers and lines in this category (previously included as part of the external insurance premium). We have adopted the base-trend-step forecast in our operating expenditure forecast.

Table 5.16 - Self-insurance ($million real, 2026/27)

Self-insurance	2028	2029	2030	2031	2032	Total
Base-trend-step forecast	2.0	2.0	2.0	2.0	2.1	**10.1**
Marsh forecasts	2.5	2.7	2.9	3.1	3.3	**14.5**
Variance	**(0.5)**	**(0.7)**	**(0.9)**	**(1.2)**	**(1.2)**	**(4.4)**

5.7.1.3 Pass through events

Residual risk events outside our control, that cannot be commercially insured or self-insured, can be addressed through the cost pass through mechanism in the Rules. Our nominated pass through events are discussed in Chapter 11 Pass Through Events.

5.7.2 AEMC levy

The AEMC is the rule maker for Australian electricity and gas markets. Under changes to the *Electricity Act 1994 (Qld)*[126] made in 2014, Powerlink, as holder of a Transmission Authority in Queensland, must pay an annual fee that is a portion of the Queensland Government's funding commitments to the AEMC.

The AEMC levy is applied to all jurisdictions across the NEM to cover the operations of the AEMC. In Queensland, the majority of the AEMC levy is passed through to Powerlink and we incur this cost as operating expenditure. Forecast expenditure for the AEMC levy over the 2027-32 regulatory period, shown in Table 5.17, is higher than the corresponding rate of change derived base-trend-step forecast. Notwithstanding this, we propose to include the base-trend-step forecast in our operating expenditure forecast, which is in line with the AER's preferred approach to such costs.

Table 5.17 - AEMC levy ($million real, 2026/27)

AEMC Levy	2028	2029	2030	2031	2032	Total
Base-trend-step forecast	6.0	6.0	6.1	6.2	6.4	**30.8**
AEMC forecast	6.6	6.7	6.7	6.6	6.6	**33.2**
Variance	**(0.6)**	**(0.7)**	**(0.6)**	**(0.5)**	**(0.2)**	**(2.5)**

5.7.3 AEMO participant and cyber security fees

This is a new category of other operating expenditure for the 2027-32 regulatory period. Due to the uncertainty around future forecasts and the absence of revealed actual costs to trend these fees we have included these as a category specific forecast.

[126] Electricity and Other Legislation Amendment Bill 2014, Queensland Government, Part 2, Amendment of Electricity Act, 1994.

In 2020, AEMO conducted a review of its current Electricity Market Participant Fee Structure. An outcome of this review was a change to the fee structure of the NEM, with a portion of the NEM fees to be levied on TNSPs starting from 1 July 2023. A Transitional Rule[127] that supported the recovery of the AEMO participant fees by passing them directly through to customers through annual prescribed transmission service prices will end on 30 June 2027 for Powerlink. Thereafter, the Rules require that these costs be recovered through existing mechanisms under the incentive-based revenue determination framework, in other words, as part of a revenue determination process with the AER.

In December 2024, the AEMC published a final determination and final Rule to confirm and clarify AEMO's cyber security role in the Rules. Consequently, in June 2025, AEMO established an additional cyber security fee structure to recover the costs of the new cyber security roles and responsibilities declared NEM project. AEMO will commence the recovery of these costs in July 2025.

The fee structure that will apply in the 2027-32 regulatory period in relation to the AEMO participant and cyber security fees is currently under review by AEMO, with the final determination expected to be published in February 2026. Powerlink has engaged with AEMO as part of the fee structure review and lodged a submission in relation to the Draft Determination which was published in September 2025.

We have based our forecast participant and cyber security fees for the Revenue Proposal on the fee structure presented in AEMO's Draft Report and Determination on NEM Participant Fee Structures[128] and subsequent AEMO update to Powerlink in December 2025.

While the fee structure defines how the fees will be allocated to participants, it does not provide a forward forecast of the fees for the five-year fee structure period from July 2026 to June 2031. For this reason, we have forecast a nominal annual increase to the expected participant fee of 6%[129] in line with the fee pathway of 6-8% indicated by AEMO in their budget and fees for 2025/26[130]. There is no similar fee pathway published in relation to the cyber security fee and therefore, we have applied no real growth to this fee. The AEMO participant and cyber security fees are shown in Table 5.18.

Table 5.18 - AEMO participant and cyber security fees ($million real, 2026/27)

	2028	2029	2030	2031	2032	Total
AEMO participant fee	14.0	14.5	15.0	15.5	16.0	**75.1**
AEMO cyber security fee	1.0	1.0	1.0	1.0	1.0	**5.0**
Total AEMO fees	**15.0**	**15.5**	**16.0**	**16.5**	**17.0**	**80.1**

5.7.4 Network support

We have included a $0 network support allowance in our operating expenditure forecast, as has been the case in previous Revenue Proposals. While Powerlink may incur system security network support costs, these have not been included in our operating expenditure forecast as they are assessed under an annual forecasting and recovery process. This approach is consistent with the Rules[131] and the AEMC's final Rule for the Improving

[127] National Electricity Amendment (Recovering the Cost of AEMO's Participant Fees) Rule 2022, Australian Energy Market Commission, October 2022.
[128] NEM Participant Fee Structures - Draft Report and Determination, Australian Energy Market Operator, September 2025.
[129] In AEMO's Budget and Fees FY26, AEMO indicates an annual fee pathway of 6-8% in relation to their NEM Core fee.
[130] Budget and Fees FY26, Australian Energy Market Operator, June 2025.
[131] National Electricity Rules, clause 6A.7.2.

Security Frameworks for the Energy Transition Rule change. These changes to cost recovery for system security network support costs commenced in December 2024.

5.7.5 Debt raising costs

Debt raising costs relate to transaction costs incurred when new debt is raised, or current lines of credit are renegotiated or extended. These costs include arrangement fees, legal fees, company credit rating fees and other transaction costs. Debt raising costs would be incurred by a prudent service provider and are an unavoidable aspect of raising debt.

The AER's standard approach is to provide an annual allowance for debt raising costs as part of operating expenditure. This is based on an efficient benchmark rather than a business's actual costs. This is consistent with the approach used to set the forecast cost of debt in the rate of return (refer Chapter 8 Rate of Return, Taxation and Inflation).

We have forecast debt raising costs of 8.61 basis points per annum based on independent advice from Incenta[132] in December 2025. Applying this basis point assumption results in forecast debt raising costs for the 2027-32 regulatory period as shown in Table 5.19.

Table 5.19 - Debt raising costs ($million real, 2026/27)

	2028	2029	2030	2031	2032	Total
Debt raising costs	4.3	4.4	4.4	4.4	4.5	**22.0**

5.8 Interaction between forecast capital and operating expenditure

The Rules[133] require that a Revenue Proposal identify and explain any significant interactions between forecast capital and operating expenditure.

We have a legislative responsibility to provide safe, reliable and cost-effective prescribed transmission services to customers and other NEM participants. To meet this obligation, we ensure network assets deliver the required reliability, availability and quality of supply through an appropriate balance of capital and operating expenditure. Consistent with our asset management framework, we use life-cycle cost analysis to deliver prudent and efficient outcomes for our customers.

There are several key network and market trends that may impact our combined capital and operating expenditure approach over the 2027-32 regulatory period. As referenced in Chapter 4 Capital Expenditure, reinvestment in the transmission network is required as our assets reach end of life, with reinvestment decisions also needing to respond to the changing energy environment. These capital investments are not only essential for maintaining the safety, reliability and security of the transmission network, but they also have direct and ongoing impacts on operating expenditure. Delays to reinvestment may result in increased operating expenditure to manage deterioration of asset condition. Conversely, additional operating expenditure to undertake enhanced maintenance of assets may enable the efficient deferral of reinvestment decisions.

Chapter 4 also references capital expenditure proposed to enhance situational awareness and decision support to improve network utilisation and customer outcomes in response to the increasing complexity of operating the transmission network. This is included in Other network capital expenditure. Delays to investment in these

[132] Incenta, Benchmark debt and equity raising costs, December 2025.
[133] National Electricity Rules, Schedule 6A.1, clause S6A.1.3(1).

enabling supportive capital expenditure initiatives may result in increased operating expenditure for network operations and asset management support.

Other non-network initiatives proposed to be undertaken in the 2027-32 regulatory period that are expected to involve interaction between capital and operating expenditure activities include:

- continuing to investigate opportunities to extend the capability of transmission network assets through non-network solutions. Contracts with generators, batteries and large loads may mitigate the power system impact from contingency events and improve power system security, allowing us to deliver additional market benefits without network augmentation or reinvestment.
- investment in IT infrastructure and software solutions including a mix of on-premise and cloud-based services. This expenditure is expected to deliver operating efficiencies, address cyber security risks, focus IT delivery for better customer outcomes, rationalise systems, and facilitate upgrades to specific programs. The IT investment program for the 2027-32 period includes both capital and operating expenditure as identified in our forecasts.

Powerlink considers the interaction of capital and operating expenditure in its investment decisions.

6 Escalation Rates

6.1 Introduction

This chapter explains how Powerlink has determined escalation rates for internal labour, external labour and materials. We have used these escalation rates as an input to forecast our operating and capital expenditure.

Key highlights:

- We sought independent advice from Oxford Economics Australia (OEA) on wage growth forecasts.
- Real labour price growth has been calculated using a simple average of the OEA forecasts and alternative forecasts sourced from Deloitte Access Economics (DAE) advice on other revenue determination processes.
- As inputs to forecast our capital and operating expenditure, we have used:
  - an average annual growth rate of 1.1% for internal labour costs and 1.1% for external labour costs over the 2027-32 regulatory period, and
  - an annual increase in the costs of materials based on the Consumer Price Index. This results in a zero real increase.

6.2 Regulatory requirements

The National Electricity Rules (Rules)[134] require our operating and capital expenditure forecasts to reasonably reflect prudent and efficient costs with a realistic expectation of demand and cost inputs required to achieve the operating and capital expenditure objectives.

6.3 Cost escalation

We have adopted real input cost changes, which excludes inflation, for internal labour, external labour and materials as presented in Table 6.1.

Table 6.1 - Real input price growth (% per annum) (Source: OEA, DAE)

	2026	2027	2028	2029	2030	2031	2032
Internal Labour	1.7	1.2	1.0	1.0	1.3	1.2	1.1
External Labour	0.4	0.7	0.9	1.1	1.3	1.1	1.0
Materials	-	-	-	-	-	-	-

[134] National Electricity Rules, clauses 6A.6.6 and 6A.6.7.

6.4 Cost escalation approach

A summary of the approach used to determine our cost escalation forecasts is provided in Table 6.2.

Table 6.2 - Approach used to forecast cost escalation

Escalation factor	Basis of forecast
Internal Labour	Simple average of the following two forecasts over the 2027-32 regulatory period: • OEA - Electricity, Gas, Water and Wastewater (EGWWS) Wage Price Index (WPI) forecast for Queensland, and • DAE Utilities WPI forecast for Queensland
External Labour	Simple average of the following two forecasts over the 2027-32 regulatory period: • OEA Construction WPI forecast for Australia, and • DAE All Industries WPI forecast for Australia
Materials	Consumer Price Index (CPI) – assumed forecast of 2.6%

Further detail on each approach is provided below.

6.4.1 Real labour price growth

Real labour price growth is based on a simple average of two independent forecasts: a forecast prepared for Powerlink by OEA and an alternative forecast being the most relevant DAE forecast prepared for the AER. This is consistent with the Australian Energy Regulator's (AER) approach[135] in recent regulatory determinations.

Our real labour price growth forecast is shown in Table 6.3.

Table 6.3 - Real labour cost escalators (% per annum) (Source: OEA, DAE)

	2026	2027	2028	2029	2030	2031	2032
Internal labour							
OEA EGWWS WPI - Qld	2.8	1.2	1.3	1.4	1.6	1.6	1.3
DAE Utilities WPI - Qld	0.6	1.1	0.7	0.6	0.9	0.8	0.8
Average	**1.7**	**1.2**	**1.0**	**1.0**	**1.3**	**1.2**	**1.1**
External labour							
OEA Construction WPI – Aus	0.4	0.7	1.0	1.3	1.5	1.2	0.9
DAE All Industries – Aus	0.4	0.7	0.7	0.9	1.0	1.0	1.0
Average	**0.4**	**0.7**	**0.9**	**1.1**	**1.3**	**1.1**	**1.0**

We provide more information on the specific forecasts used in preparing our Revenue Proposal, together with the source and rationale for selecting the alternative forecast, in the following sections.

135 Final Decision, Energex Distribution Determination 2025-2030: Attachment 6 Operating Expenditure, Australian Energy Regulator, April 2025, p.25. Note: this approach was also applied to Final Decisions published in 2025 for Ergon Energy and Jemena Gas Networks, previous Powerlink determinations, and recent Draft Decisions in respect to Victorian DNSPs.

6.4.1.1 Oxford Economics Australia forecast

We engaged OEA to provide an independent expert opinion on WPI forecasts specific to Queensland's business environment and economic outlook. OEA is a leading provider of industry research, analysis and forecasting services. OEA's wage growth forecasts for Queensland and nationally leverage their knowledge of the Australian economy and industrial sectors, to link labour market conditions to overarching macroeconomic and regional drivers.

OEA provided WPI forecasts over the seven-year period from 2025/26 to 2031/32. This captures the last two years of our current 2022-27 regulatory period and the five years of the 2027-32 regulatory period. Separate forecasts were prepared for internal and external labour. This reflects the use of our own workforce and external contractors to deliver our operational and capital works:

- internal labour price growth - Electricity, Gas, Water and Wastewater (EGWWS) sector specific to Queensland has been used, and
- external labour price growth - Construction sector for Australia has been used, recognising that the labour market accessed by contractors is not constrained to Queensland.

The advice from OEA is that over the forecast period, the Queensland EGWWS WPI average growth in nominal terms of 4.0% per annum (applied to internal labour) is expected to remain higher than the Australian EGWWS WPI average of 3.8% per annum. In its report, OEA forecast utilities wages to increase by more than the national (All Industries) average over the forecast period due, in summary, to the following factors:

- *the electricity, gas and water sector is a largely capital-intensive industry whose employees have higher skill, productivity and commensurately higher wage levels than most other sectors*
- *… outcomes for collective agreements, which cover 62% of the workforce, remain above the wage increases for the national 'all industry' average …*
- *increases in individual agreements … are expected to remain elevated as the labour market remains tight …*
- *demand for skilled labour will remain high and strengthen with the sustained increases in overall construction activity and high levels of utilities investment from FY25 to FY32…*[136]

In addition, OEA noted that the national (All Industries) average tends to be dragged lower by some of its constituent groups (retail, trade, hospitality, etc.). OEA's report is provided in Appendix 5.01.

6.4.1.2 Alternative forecast

We anticipate that the AER will engage its own consultant to provide an alternative WPI forecast for its Draft Decision, which will be updated for its Final Decision.

For the alternative forecast in our Revenue Proposal, we have used the DAE Labour Price Growth Forecasts report used by the AER in its Final Decision for Ergon's 2025-30 revenue determination[137]. As this includes forecast WPI to 2029/30, we have applied a trend to the forecast to derive wage growth for the two final years of our 2027-32 regulatory period.

We consider this to be an appropriate approach to estimating wage growth as it provides a reasonable placeholder for the alternative forecast while recognising the specific demand in Queensland.

[136] Labour Cost Escalation Forecasts to 2031/32 – Final Report for Powerlink, Oxford Economics Australia, October 2025, pages 3-4.
[137] Labour price growth forecasts, Deloitte Access Economics, March 2025.

6.4.2 Real materials price growth

As discussed earlier in our Revenue Proposal, there have been significant materials price increases over the 2022-27 regulatory period, far beyond the level of CPI (refer Chapter 2 Operating Environment). Although there are still many unknowns in the global economic environment, along with the broader rate of global and local inflation, the rate of price growth appears to be moderating back towards long-term growth in line with CPI. To be clear, there is no indication that materials prices will decline in real terms to their previous levels.

While noting there are substantial on-going risks as global demand for major plant items and materials remains high, we propose a real price growth of zero for materials in our expenditure forecasts for the 2027-32 regulatory period. This reflects the expectation that materials costs will revert to increases that broadly align with CPI.

For our 2027-32 Revenue Proposal, we have applied a CPI forecast of 2.6% for real materials price growth, based on the Reserve Bank of Australia's November 2025 *Statement of Monetary Policy*[138] (refer Chapter 8 Rate of Return, Taxation and Inflation).

6.4.3 Interaction with expenditure incentive schemes

The incentive-based economic regulatory framework in Australia is designed such that a regulated network business reveals its efficient costs to provide prescribed transmission services. The Capital Expenditure Incentive Scheme (CESS) and the Efficiency Benefit Sharing Scheme (EBSS) are designed to balance the incentives faced by a network business to undertake efficient expenditure over time. They are based on allowing a network business to retain benefits from spending less than the efficient expenditure allowances, while penalising it for spending more than the efficient allowances.

Powerlink forecasts it will incur substantial penalties under both the CESS and the EBSS from the 2022-27 regulatory period, largely due to significant increases in the real prices of labour and materials above inflation that were outside of Powerlink's control. These labour and materials increases have been substantially greater than the forecast escalation rates allowed for within our 2022-27 revenue determination that determined the efficient expenditure allowances.

Consistent with the incentive-based framework, this Revenue Proposal adopts the current revealed prices for labour and materials as the basis for our capital and operating expenditure forecasts. We then apply our proposed cost escalation approach for both labour and materials to forecast these prices during the 2027-32 regulatory period as described above. Our proposed cost escalation approach is consistent with that adopted by the AER in recent revenue determinations.

[138] Statement on Monetary Policy – November 2025, Reserve Bank of Australia, November 2025.

7 Regulatory Asset Base

7.1 Introduction

This chapter outlines Powerlink's approach to calculating the opening Regulatory Asset Base (RAB) as at 1 July 2027 and our forecast RAB for each year of the 2027-32 regulatory period.

Key highlights:

- Our opening RAB as at 1 July 2027 is forecast to be $8,322.6 million ($ nominal).
- The RAB is forecast to increase by $1,642.1 million ($ nominal) over the 2027-32 regulatory period[139].
- The increase is primarily driven by higher forecast capital expenditure within the period largely due to reinvestment in ageing network assets, and the need to enhance both physical and cyber security in response to the *Security of Critical Infrastructure Act 2018*.
- The closing RAB as at 30 June 2032 is forecast to be $9,964.8 million ($ nominal).

7.2 Regulatory requirements

The National Electricity Rules (Rules)[140] set out the requirements for establishing the opening value of our RAB. We are also required to provide the annual RAB calculations for each year of the current 2022-27 regulatory period[141]. This is done using the Australian Energy Regulator's (AER's) Roll Forward Model (RFM)[142].

The Rules[143] require that the RAB is the value of assets used to provide prescribed transmission services, but only to the extent that they are used to provide such services. The Rules[144] require that the RAB for each year of the regulatory period be reduced by the disposal value of any asset disposed of in the period.

The Rules[145] also allow for the value of assets that previously provided non-prescribed transmission services to be transferred into the RAB as part of a revenue determination. The transfer amount is limited to the extent that such capital expenditure relates to an asset that is now used for the provision of prescribed transmission services.

7.3 Our approach

We established the opening value of our RAB and rolled it forward for each year of the regulatory period in accordance with the Rules[146]. We used the AER's RFM to establish the opening RAB as at 1 July 2027 and the AER's Post-Tax Revenue Model (PTRM)[147] to calculate the forecast RAB for the 2027-32 regulatory period.

We continued to apply year-by-year depreciation tracking (refer Chapter 9 Depreciation) and have used the AER's Depreciation Tracking Module (DTM)[148] to do so.

[139] Based on a comparison of 1 July 2027 opening RAB to 30 June 2032 closing RAB.
[140] National Electricity Rules, Schedule 6A.2, clause S6A.2.1(f).
[141] National Electricity Rules, clause 6A.6.1 and Schedule 6A.1, clause S6A.1.3(5).
[142] Electricity Transmission Network Service Provider Roll Forward Model (version 4.1), Australian Energy Regulator, May 2022.
[143] National Electricity Rules, clause 6A.6.1(a).
[144] National Electricity Rules, Schedule 6A.2, clause S6A.2.1(f)(6).
[145] National Electricity Rules, Schedule 6A.2, clause S6A.2.1(f)(8).
[146] National Electricity Rules, Schedule 6A.2, clause S6A.2.1(f).
[147] Electricity Transmission Network Service Provider Post-Tax Revenue Model (version 6), Australian Energy Regulator, March 2025.
[148] Electricity Transmission Network Service Provider RFM - Depreciation Tracking Module (version 1), April 2020.

Prior to publication of the AER's Final Decision on Powerlink's 2027-32 Revenue Proposal in April 2027, we will update our forecast opening RAB as at 1 July 2027 to reflect the actual capital expenditure in 2025/26 and update the forecast RAB roll forward for the 2027-32 regulatory period accordingly.

7.4 Opening RAB as at 1 July 2027

To establish the forecast opening RAB as at 1 July 2027, we have adjusted the opening RAB as at 1 July 2022 for capital expenditure and regulatory depreciation as shown in Table 7.1.

Following engagement with the AER, we have calculated the opening RAB using the actual/forecast capital expenditure for years 2023 to 2025 recast to disburse the adjustments applied in 2024/25. We discuss these adjustments further in Chapter 4 Capital Expenditure.

Table 7.1 - Establishment of opening RAB as at 1 July 2027 ($million nominal)

	2023	2024	2025	2026 forecast	2027 forecast
Opening RAB	7,157.9	7,614.5	7,806.7	7,821.2	8,046.3
Capital expenditure as incurred (1)	231.4	250.3	209.6	360.7	385.3
Regulatory depreciation (2)	225.2	(58.1)	(195.1)	(135.6)	(146.1)
Closing RAB	7,614.5	7,806.7	7,821.2	8,046.3	8,285.5
Difference between forecast and actual capital expenditure in 2021/22					0.3
Return on capital for the difference between forecast and actual expenditure in 2021/22					0.1
Final year asset adjustment (3)					36.7
Opening RAB as at 1 July 2027					**8,322.6**

a. Net of disposals, adjusted for inflation and one-half Weighted Average Cost of Capital (WACC) allowance.[149]. The roll forward also reflects forecast capitalised movements in provisions.
(1) Depreciation is based on forecast depreciation as approved by the AER for the 2022-27 regulatory period and is net of indexation applied to the RAB.
(2) RAB addition relating to the portion of existing non-prescribed assets that will be utilised to provide prescribed transmission services, as outlined in Section 7.6.1.

[149] PTRM calculates the return on capital based on the opening RAB and capital expenditure is assumed to occur half-way through the year. To address this timing difference, a half WACC is added to compensate for the six-month period before capital expenditure is included in the RAB.

7.5 Forecast RAB for the 2027-32 regulatory period

The forecast RAB for each year of the 2027-32 regulatory period is shown in Table 7.2.

Table 7.2 - Forecast RAB roll forward 2027-32 regulatory period ($million nominal)

	2028	2029	2030	2031	2032
Opening RAB	8,322.6	8,636.6	8,978.1	9,238.6	9,614.0
Capital expenditure, as incurred (1)	536.0	536.5	467.9	601.3	595.1
Regulatory depreciation	(222.0)	(194.9)	(207.4)	(225.9)	(244.3)
Closing RAB	**8,636.6**	**8,978.1**	**9,238.6**	**9,614.0**	**9,964.8**

(1) Net of disposals, adjusted for inflation and one-half WACC allowance. The roll forward also reflects forecast capitalised movements in provisions.

7.6 RAB additions and removals

7.6.1 Additions

We have included an asset transfer of $36.7 million in the closing RAB at 30 June 2027 in our Revenue Proposal. This amount reflects the portion of existing non-prescribed assets that will be used to provide prescribed transmission services. In determining the appropriate transfer value, we have referred to the requirements of the Rules and our Cost Allocation Methodology.

In our draft Revenue Proposal, published in September 2025, this amount was included as forecast capital expenditure in the 2027-32 regulatory period. However, as the asset is expected to be capitalised and provide non-prescribed transmission services within the current 2022-27 regulatory period, we consider it appropriate to treat this as an asset transfer to the RAB, rather than as forecast capital expenditure. We engaged with the Revenue Proposal Reference Group (RPRG) on this matter in December 2025.

We estimate that the impact on customers from this inclusion is negligible and has not had any consequential impact on our operating or capital expenditure forecasts for the 2027-32 regulatory period. Further information to support our proposed RAB additions is provided in Appendix 7.01 Regulatory Asset Base Transfers.

7.6.2 Removals

We have removed $2.8 million in assets from our RAB which have been repurposed to provide non-prescribed transmission services. This approach ensures that assets with no enduring need for the provision of prescribed transmission services and can be repurposed, are removed from the RAB. It also means that customers who will derive benefit from the use of the assets going forward will pay for them. This adjustment has been effected by means of an asset disposal.

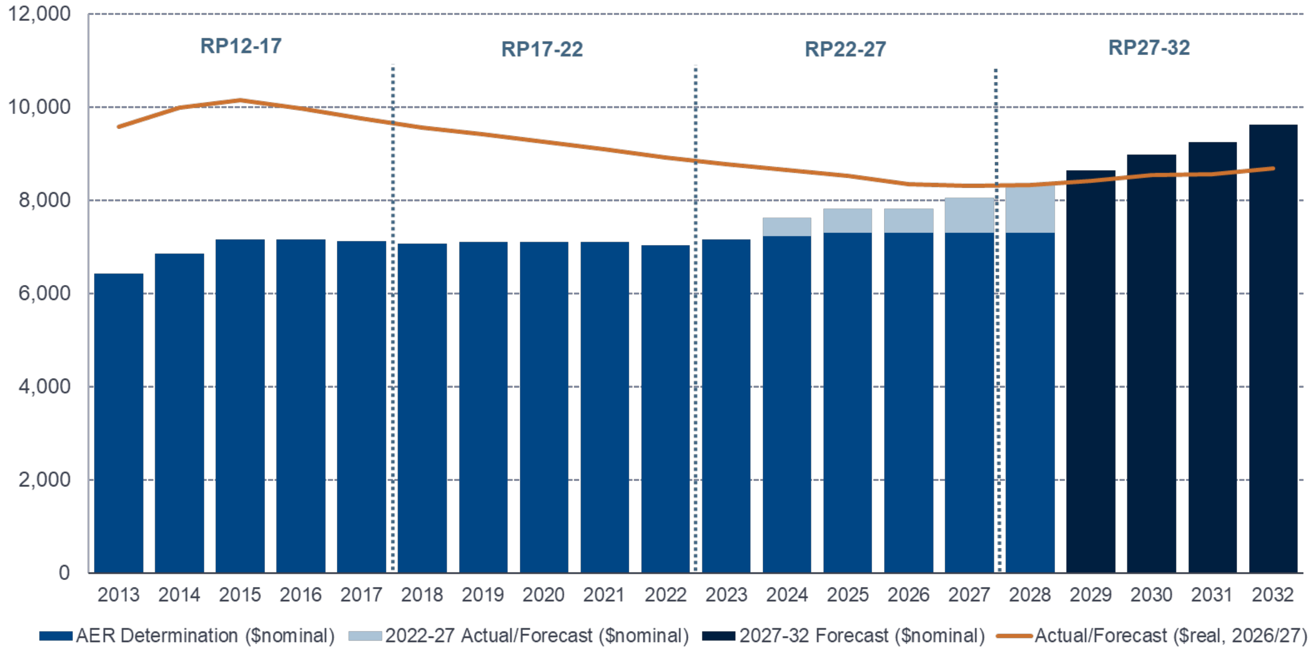
Given the customer-specific and commercial-in-confidence nature of our proposed RAB removals, further information to support our proposal is provided to the AER on a confidential basis in Appendix 7.01 Regulatory Asset Base Transfers.

7.7 Historical and forecast RAB

As shown in Figure 7.1, our RAB is forecast to increase by $1,642.1 million ($ nominal) over the 2027-32 regulatory period[150]. This is an increase of $441.9 million in real, 2026/27. The increase is primarily driven by higher forecast capital expenditure within the period, largely due to reinvestment in ageing network assets and the need to enhance both physical and cyber security in response to the *Security of Critical Infrastructure Act 2018* (refer Chapter 4 Capital Expenditure).

The higher forecast capital expenditure also reflects the increased cost of delivering prescribed transmission services due to increased global demand for major plant items and competition for scarce skilled resources (refer Chapter 2 Operating Environment).

Figure 7.1 - Opening RAB 2012/13 to 2031/32 ($million)



150 Based on a comparison of 1 July 2027 opening RAB to 30 June 2032 closing RAB.

8 Rate of Return, Taxation and Inflation

8.1 Introduction

This chapter outlines Powerlink's approach to estimating the rate of return (RoR), also referred to as the Weighted Average Cost of Capital (WACC), taxation and inflation for the 2027-32 regulatory period.

Key highlights:

- We estimate a RoR of 6.29% for the first year of the 2027-32 regulatory period (2027/28), calculated using the Australian Energy Regulator's (AER's) binding 2022 Rate of Return Instrument (RoRI).
    - The final RoR will be updated by the AER in its Final Decision using market data and the 2026 RoRI, expected to be finalised in December 2026.
- The RoR reflects a significant shift in the interest rate environment since our previous revenue determination in April 2022, with increases in the risk-free rate and the cost of debt.
- Our taxation allowance is estimated using the AER's Post-Tax Revenue Model (PTRM)[151], applying a corporate tax rate of 30% and a gamma value of 0.57, consistent with the 2022 RoRI.
- Our forecast inflation is 2.60%, calculated using the methodology set out in the PTRM. The AER will update the inflation forecast in its Final Decision on Powerlink's Revenue Proposal for the 2027-32 regulatory period to reflect the latest available forecasts published by the Reserve Bank of Australia (RBA).

8.2 Regulatory requirements

Under the National Electricity Rules (Rules)[152], the return on capital allowance is calculated by multiplying the allowed RoR by the opening value of our Regulatory Asset Base (RAB) for each year of the regulatory period.

The RoR[153] must be determined in accordance with the current RoRI published by the AER[154]. These calculations are included in the RoR Model submitted as part of this Revenue Proposal[155].

For inflation, the Rules[156] require the AER to specify in the PTRM a methodology that is likely to result in the best estimate of expected inflation.

The Rules[157] also require that our corporate tax allowance be calculated by applying the expected statutory income tax rate to the estimated taxable income for each year of the regulatory period, less the value of imputation credits (gamma).

8.3 Rate of return

8.3.1 Overview

Our estimated RoR for the 2027-32 regulatory period is shown in Table 8.1.

[151] Electricity Transmission Network Service Provider Post-Tax Revenue Model (version 6), Australian Energy Regulator, March 2025.
[152] National Electricity Rules, clause 6A.6.2.
[153] National Electricity Rules, Chapter 10, definition of *allowed rate of return*.
[154] Rate of Return Instrument (version 1.2), Australian Energy Regulator, March 2024.
[155] National Electricity Rules, Schedule 6A.1, clause S6A.1.3(4A)
[156] National Electricity Rules, clause 6A.5.3(b)(1).
[157] National Electricity Rules, clause 6A.6.4.

Table 8.1 - Rate of Return 2027-32

	2028	2029	2030	2031	2032
Return on equity (nominal, post-tax)	8.39%	8.39%	8.39%	8.39%	8.39%
Return on debt (nominal, pre-tax)	4.89%	5.01%	5.12%	5.38%	5.73%
Gearing	60.00%	60.00%	60.00%	60.00%	60.00%
WACC (nominal, vanilla)(1)	**6.29%**	**6.37%**	**6.43%**	**6.58%**	**6.80%**

(1) Nominal vanilla WACC is the weighted average of the post-tax nominal return on equity and pre-tax nominal return on debt.

8.3.2 Our approach

The RoR has been calculated in accordance with the 2022 RoRI. The RoR will be updated in the AER's Final Decision in line with the nominated averaging periods and the 2026 RoRI, which it anticipates finalising in December 2026. Nominated averaging periods have been provided to the AER on a confidential basis in Appendix 8.01 Nominated Averaging Periods.

8.3.2.1 Return on equity

Applying the 2022 RoRI, we estimate a return on equity of 8.39% for the 2027-32 regulatory period. The risk-free rate is based on a 20-business-day averaging period ending 17 December 2025[158]. This is a placeholder estimate, with the final return to be determined in accordance with the 2026 RoRI and the actual risk-free rate in line with our nominated averaging period. The parameter values are presented in Table 8.2.

Table 8.2 - Return on equity

Parameter	Estimate
Risk-free rate	4.67%
Equity beta	0.60
Market risk premium	6.20%
Return on equity	**8.39%**

8.3.2.2 Return on debt

Applying the 2022 RoRI, our indicative return on debt for the first year of the 2027-32 regulatory period (2027/28) is 4.89%. Under the AER's trailing average approach, the AER will update our return on debt annually throughout the regulatory period to reflect prevailing rates at that time. For our Revenue Proposal, we have adopted an averaging period of the 20 business days to 28 November 2025.

This results in the following estimates in Table 8.3.

Table 8.3 - Return on debt 2027-32

	2028	2029	2030	2031	2032
Return on debt (nominal, pre-tax)	4.89%	5.01%	5.12%	5.38%	5.73%

[158] The risk-free rate is the simple average of the daily 10-year yield to maturity for a Commonwealth Government Security, converted into an effective annual rate, for each specific business day over the averaging period.

8.4 Taxation

Our taxation forecast for the 2027-32 regulatory period is presented in Table 8.4.

Table 8.4 - Taxation ($million nominal)

	2028	2029	2030	2031	2032	Total
Corporate tax	53.6	48.6	41.7	44.3	42.0	**230.2**
Value of imputation credits	(30.6)	(27.7)	(23.8)	(25.2)	(24.0)	**(131.2)**
Taxation	**23.1**	**20.9**	**17.9**	**19.0**	**18.1**	**99.0**

We have estimated our taxation allowance using the PTRM and the 2022 RoRI, applying:

- a statutory tax rate of 30% per year, and
- a gamma value of 0.57 to estimate the value of imputation credits.

Our approach to the immediate expensing of capital expenditure and tax depreciation is consistent with our 2023-27 Revenue Proposal, which the AER accepted in its Final Decision to our 2022-27 revenue determination. This approach is in line with the AER's 2018 Regulatory Tax Review.

8.4.1 Immediate expensing of capital expenditure

Our forecast of immediately deductible capital expenditure is based on the average of actual immediate deductions of capitalised overheads in previous years. We confirm that our current tax policy will remain unchanged for the 2027-32 regulatory period.

8.4.2 Diminishing value depreciation

We continue to apply the diminishing value (DV) method for tax depreciation for all new capital expenditure, except for buildings and in-house software, which continue to be depreciated using the straight-line method, consistent with the *Income Tax Assessment Act 1997* (ITAA).

8.5 Forecast inflation

We calculated expected inflation using the AER's methodology set out in the PTRM. Expected inflation is calculated as the geometric average of inflation rates over the 2027-32 regulatory period based on the Reserve Bank of Australia (RBA) forecasts and a glide path to the midpoint of the RBA's target inflation band (2.5%) in the fifth year. We have used the RBA's *Statement of Monetary Policy* in November 2025[160] to derive a placeholder estimate of 2.60% for this Revenue Proposal.

[160] Statement on Monetary Policy – November 2025, Reserve Bank of Australia, November 2025.

9 Depreciation

9.1 Introduction

This chapter outlines Powerlink's proposed return of capital allowance (also referred to as regulatory depreciation) for the 2027-32 regulatory period. Depreciation enables investors to recover the cost of their capital investment over the economic life of the asset.

Key highlights:

- Our forecast regulatory depreciation for the 2027-32 regulatory period is $1,094.5 million ($ nominal).
- In real 2026/27 terms, this is $1,012.3 million which is $109.6 million (12%) higher than the current 2022-27 regulatory period.
- We do not propose to apply any depreciation adjustments relating to financeability, as our Revenue Proposal does not include any actionable Integrated System Plan (ISP) projects.
- We continue to apply the year-by-year depreciation tracking approach in forecasting depreciation.
- We propose to maintain the same asset classes and standard asset lives as approved by the AER in its determination for Powerlink's current regulatory period.
- We propose to roll forward our Regulatory Asset Base (RAB) using forecast depreciation to calculate the opening RAB for the subsequent 2032-37 regulatory period.
- We do not propose any accelerated depreciation.

9.2 Regulatory requirements

The National Electricity Rules (Rules)[161] require that depreciation schedules use a profile that reflects the nature of each asset class over its economic life.

9.3 Depreciation forecast

Under the regulatory framework, regulatory depreciation is calculated as straight-line depreciation less the inflation adjustment on the opening RAB. Straight-line depreciation reduces an asset's value evenly over its useful life. To calculate the value of the opening RAB for any given year, the previous year's RAB must be adjusted for inflation to maintain its real value at the start of the subsequent year[162]. We have sourced the straight-line depreciation forecasts (in $ nominal) from the Post-Tax Revenue Model for the 2027-32 regulatory period.

Our depreciation forecast for the 2027-32 regulatory period is set out in Table 9.1.

[161] National Electricity Rules, clause 6A.6.3.
[162] National Electricity Rules, Schedule S6A.2, clause 6A.2.4(c)(4).

Table 9.1 - Forecast regulatory depreciation 2027-32 regulatory period ($million nominal)

	2028	2029	2030	2031	2032	Total
Straight-line depreciation	438.4	419.5	440.8	466.1	494.3	**2,259.1**
Less inflation adjustment on opening RAB	(216.4)	(224.5)	(233.4)	(240.2)	(250.0)	**(1,164.5)**
Regulatory depreciation	**222.0**	**194.9**	**207.4**	**225.9**	**244.3**	**1,094.5**

Our forecast regulatory depreciation is $1,094.5 million ($ nominal). In real 2026/27 terms, this is $1,012.3 million which is $109.6 million (12.1%) higher than the current 2022-27 regulatory period. The increase is primarily driven by growth in our RAB resulting from capital works completed during the current regulatory period.

This forecast reflects the inputs in our Revenue Proposal and will be updated by the AER in its Final Decision to reflect the approved capital expenditures and updated inflation forecast.

9.4 Our approach

We have calculated regulatory depreciation as a forecast depreciation less the inflation adjustment to the opening RAB, consistent with the Rules and the Australian Accounting Standards[163]. We use the AER's Post-Tax Revenue Model (PTRM)[164] to calculate the depreciation forecast for new assets from 1 July 2027 and the AER's Roll Forward Model (RFM)[165] and Depreciation Tracking Module (DTM)[166] for existing assets as forecast at 30 June 2027.

The PTRM introduces key changes to align with the Australian Energy Market Commission's (AEMC's) 2024 rule change on accommodating financeability in the regulatory framework[167] and the AER's Financeability Guideline[168]. It allows for accelerated depreciation to address demonstrated financeability issues resulting from the delivery of actionable ISP projects. Our Revenue Proposal does not include any actionable ISP projects and therefore no financeability related depreciation adjustments are proposed for the 2027-32 regulatory period. Powerlink may consider the application of these mechanisms in future regulatory processes should actionable ISP projects be included.

We also assessed the treatment of assets where the expected life has been shortened due to technical or operational reasons that may be eligible for application of accelerated depreciation. However, Powerlink has opted not to apply accelerated depreciation to these assets in the 2027-32 regulatory period to avoid short-term price impacts on customers.

In summary, we do not propose to apply any depreciation adjustments relating to financeability or accelerated depreciation for the 2027-32 regulatory period.

9.4.1 Year-by-year depreciation tracking

We continue to use a year-by-year depreciation tracking approach to calculate depreciation. Under this method, new capital expenditure is grouped by asset class, and each asset class is depreciated separately over its approved

[163] Australian Accounting Standard AASB 116 Property, Plant and Equipment.
[164] Electricity Transmission Network Service Provider Post-Tax Revenue Model (version 6), Australian Energy Regulator, March 2025.
[165] Electricity Transmission Network Service Provider Roll Forward Model (version 4.1), Australian Energy Regulator, May 2022.
[166] Electricity Transmission Network Service Provider RFM - Depreciation Tracking Module (version 1), Australian Energy Regulator, April 2020.
[167] National Electricity Amendment (Accommodating financeability in the regulatory framework) Rule 2024, Australian Energy Market Commission, March 2024.
[168] Financeability guideline – Final decision, Australian Energy Regulator, November 2024.

standard life, ensuring that the recovery profile of our costs reflects the economic lives of our assets. We have provided our year-by-year depreciation tracking model with this Revenue Proposal.

9.4.2 Use of forecast depreciation

The AER determined that it will use forecast depreciation to:

- roll forward the RAB for the 2022-27 regulatory period to establish our opening RAB as at 1 July 2027[169], and
- establish our opening RAB as at 1 July 2032 for commencement of the subsequent 2032-37 regulatory period[170].

9.5 Asset classes and asset lives

The standard life we propose to apply to each asset class are shown in Table 9.2. We propose to apply the same standard asset lives for the 2027-32 regulatory period as applied in the current 2022-27 regulatory period.

Table 9.2 - Standard asset lives – as at 30 June 2027 (years)

Asset class	Standard life (1)
Transmission lines - overhead	50
Transmission lines - underground	45
Transmission lines - refit	30
Substations primary plant	40
Substations secondary systems	15
Communications - other assets	15
Communications - civil works	40
Network switching centres	12
Land	n/a
Easements	n/a
Commercial buildings	40
Computer equipment	5
Office furniture and miscellaneous	7
Office machines	7
Vehicles	7
Moveable plant	7
Insurance spares	n/a
Buildings - capital works	40
In-house software	5

(1) Asset classes with 'n/a' identified for its standard life do not depreciate.

[169] Powerlink 2022-27 Final Decision, Australian Energy Regulator, April 2022, p.38.
[170] Framework and Approach Powerlink transmission determination 2027-32, Australian Energy Regulator, July 2025.

10 Maximum Allowed Revenue and Price Impact

10.1 Introduction

This chapter outlines Powerlink's Maximum Allowed Revenue (MAR) and forecast price impacts for the 2027-32 regulatory period.

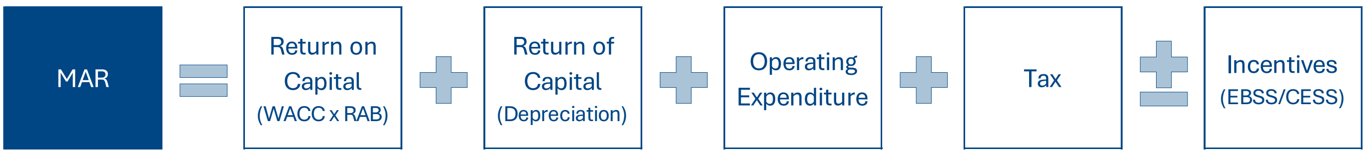
Key highlights:

- Forecast unsmoothed MAR for the 2027-32 regulatory period is $5,702.0 million ($ nominal) or $5,265.3 million ($ real, 2026/27). This is $1,059.0 million (25%) higher than our allowed MAR in real terms for the 2022-27 regulatory period. The increase in MAR is mainly driven by:
    - significantly higher rates of return, reflecting a sharp increase in the interest rate environment relative to the historically low rates in the current regulatory period
    - growth in the Regulatory Asset Base (RAB) due to increased capital expenditure, impacting return on capital and depreciation, and
    - higher operating expenditure, reflecting changes in the operating environment.
- The increases are partly offset by forecast negative revenue adjustments under the Australian Energy Regulator's (AER's) Capital Expenditure Sharing Scheme (CESS) and Efficiency Benefit Sharing Scheme (EBSS).
- The increase in MAR results in a forecast increase in the average indicative transmission price of 5% in nominal terms in the first year of the next regulatory period, with 5% increases in each subsequent year.
- For average residential and small business customers, this represents an indicative increase in the first year of $7 and $14, respectively, based on the assumed tariff and consumption[171].

10.2 Regulatory requirements

We determine the MAR using the building block approach outlined in the National Electricity Rules (Rules)[172]. This approach calculates the unsmoothed annual revenue requirement, as shown in Figure 10.1.

Figure 10.1 - MAR building block approach



WACC: Weighted Average Cost of Capital (rate of return)
RAB: Regulatory Asset Base
EBSS: Efficiency Benefit Sharing Scheme
CESS: Capital Expenditure Sharing Scheme

[171] The transmission component of electricity bills is based on Australian Energy Regulator's (AER) Default Market Offer 2025-26 Final Determination (DMO 7), May 2025 and Energex's 2025-26 Pricing proposal Overview, May 2025. The assumed residential and small business consumption is based on AER's DMO 7 with median energy usage of 4,600 kWh pa and 10,000 kWh pa, respectively.
[172] National Electricity Rules, clause 6A.5.4.

The Rules[173] require that this annual revenue requirement be smoothed using an X-factor, ensuring the net present value (NPV) of the smoothed revenue equals that of the unsmoothed revenue over the regulatory period. Additionally, the smoothed MAR in the final regulatory year should closely align with the unsmoothed MAR.

Within the period, the Rules provide for various adjustments to the MAR, including:

- approved pass throughs[174] (refer Chapter 11 Pass Through Events)
- approved contingent project allowances[175] (refer Chapter 4 Capital Expenditure), and
- updates for other inputs such as inflation and the annual cost of debt update (refer Chapter 8 Rate of Return, Taxation and Inflation), as well as annual Service Target Performance Incentive Scheme outcomes (refer Chapter 13 Incentive Schemes)[176].

10.3 Forecast total revenue

Our total unsmoothed MAR for each year of the 2027-32 regulatory period is shown in Table 10.1. These figures are calculated using the AER's Post-Tax Revenue Model (PTRM)[177], which applies the building block approach to calculate the unsmoothed annual revenue requirement.

Table 10.1 - Unsmoothed revenue requirement ($million nominal)

	2028	2029	2030	2031	2032	Total
Return on capital	523.5	549.7	577.1	608.3	653.4	**2,911.9**
Return of capital (1)	222.0	194.9	207.4	225.9	244.3	**1,094.5**
Operating expenditure	366.2	385.0	393.0	408.8	428.3	**1,981.3**
Revenue adjustments (2)	(109.8)	(106.8)	(83.8)	(53.3)	(31.0)	**(384.8)**
Taxation	23.1	20.9	17.9	19.0	18.1	**99.0**
Unsmoothed revenue requirement	**1,025.0**	**1,043.8**	**1,111.6**	**1,208.6**	**1,313.0**	**5,702.0**

(1) Return of capital is also referred to as regulatory depreciation, refer Chapter 9 Depreciation.
(2) Revenue adjustments comprise CESS and EBSS carryover amounts, refer Chapter 13 Incentive Schemes.

Section 10.5 outlines the approach used to calculate each building block component.

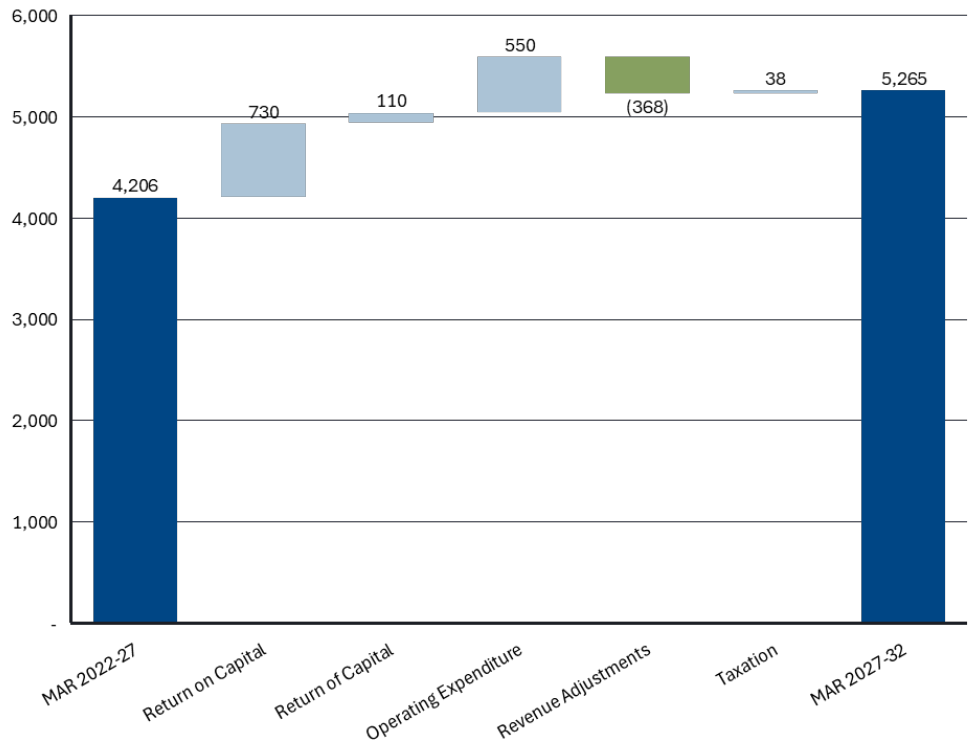
10.4 Change in MAR from the 2022-27 regulatory period

Our unsmoothed MAR is forecast to increase by $1,059.0 million (25%) in real 2026/27 terms compared to our allowed MAR for the 2022-27 regulatory period.

Figure 10.2 shows the key drivers of revenue change between our current and next regulatory periods.

[173] National Electricity Rules, clause 6A.6.8.
[174] National Electricity Rules, clause 6A.7.2, 6A.7.2A and 6A.7.3.
[175] National Electricity Rules, clause 6A.8.
[176] National Electricity Rules, clause 6A.7.4.
[177] Electricity Transmission Network Service Provider Post-Tax Revenue Model (version 6), Australian Energy Regulator, March 2025.

Figure 10.2 - Drivers of unsmoothed MAR change ($million real, 2026/27)



In summary, these changes reflect:

- **Return on capital:** increase of $730.2 million, driven by a higher rate of return (refer Chapter 8 Rate of Return, Taxation and Inflation) and growth in the RAB (refer Chapter 7 Regulatory Asset Base). The RAB growth reflects:
    - higher capital expenditure in the current 2022-27 regulatory period, driven by a significantly different operating environment, including expanded investment needs, new regulatory obligations, and substantial cost pressures from global supply chain disruptions, inflation and the energy system transition (refer Chapter 4 Capital Expenditure), and
    - higher forecast capital expenditure in the 2027-32 regulatory period, driven by reinvestment in ageing network assets, system security needs, upgrades to our Virginia complex and the establishment of facilities in Central Queensland to support the network outside of South-East Queensland (refer Chapter 4 Capital Expenditure).
- **Return of capital:** increase of $109.6 million, reflecting growth in the RAB (refer Chapter 9 Depreciation).
- **Operating expenditure:** increase of $550.0 million, driven by changes in the operating environment including increased demand for skilled labour, greater operating complexity and new regulatory requirements (refer Chapter 5 to Operating Expenditure).
- **Revenue adjustments:** reduction of $368.5 million, driven by forecast net carryovers under CESS and EBSS due to additional capital and operating expenditure compared to allowances in the current 2022-27 period (refer Chapter 13 Incentive Schemes).
- **Taxation:** increase of $37.6 million, primarily due to the higher MAR (refer Chapter 8 Rate of Return, Taxation and Inflation).

10.5 Our approach

We used the AER's PTRM to calculate the MAR. We have engaged with our customers extensively on key changes to our approach that impact our forecast MAR (refer Chapter 3 Customer Engagement), such as our capital and operating expenditure forecasts.

The AER will update its revenue building blocks for the relevant inputs and forecasts that underpin the MAR in its Final Decision in our 2027-32 Revenue Proposal, which is due to be published in April 2027.

10.5.1 Regulatory Asset Base

The value of our RAB determines our return on and return of capital allowances. Our forecast opening RAB at 1 July 2027 is $8,322.6 million ($ nominal). Our approach to calculating this is outlined in Chapter 7 Regulatory Asset Base.

We have forecast a roll-forward of our RAB for each year of the 2027-32 regulatory period based on our forecasts for inflation, capital expenditure and regulatory depreciation. This is summarised in Table 10.2.

Table 10.2 - Forecast RAB roll-forward 2027-32 regulatory period ($million nominal)

	2028	2029	2030	2031	2032
Opening RAB	8,322.6	8,636.6	8,978.1	9,238.6	9,614.0
Capital expenditure, as incurred (1)	536.0	536.5	467.9	601.3	595.1
Regulatory depreciation	(222.0)	(194.9)	(207.4)	(225.9)	(244.3)
Closing RAB	**8,636.6**	**8,978.1**	**9,238.6**	**9,614.0**	**9,964.8**

(1) Net of disposals, adjusted for inflation and one-half Weighted Average Cost of Capital (WACC) allowance[178]. The roll-forward also reflects capitalised movements in provisions.

10.5.2 Return on capital

The return on capital is calculated by applying our rate of return (also referred to as the Weighted Average Cost of Capital, or WACC) to the opening RAB in each year of the regulatory period, as detailed in Chapter 8 Rate of Return, Taxation and Inflation.

Our return on capital forecast is presented in Table 10.3.

Table 10.3 - Return on capital ($million nominal)

	2028	2029	2030	2031	2032	Total
Opening RAB	8,322.6	8,636.6	8,978.1	9,238.6	9,614.0	n/a
Rate of return	6.29%	6.37%	6.43%	6.58%	6.80%	n/a
Return on capital	**523.5**	**549.7**	**577.1**	**608.3**	**653.4**	**2,911.9**

[178] The PTRM calculates the return on capital based on the opening RAB and capital expenditure is assumed to occur half-way through the year. To address this timing difference, a half WACC is added to compensate for the six-month period before capital expenditure is included in the RAB.

10.5.3 Return of capital

Our return of capital (also referred to as regulatory depreciation) is calculated by deducting the inflation adjustment made to the RAB from forecast depreciation, as shown in Table 10.4.

More information on our approach to calculating depreciation is provided in Chapter 9 Depreciation.

Table 10.4 - Return of capital ($million nominal)

	2028	2029	2030	2031	2032	Total
Straight-line depreciation (1)	438.4	419.5	440.8	466.1	494.3	**2,259.1**
Less inflation adjustment opening RAB	(216.4)	(224.5)	(233.4)	(240.2)	(250.0)	**(1,164.5)**
Return of capital	**222.0**	**194.9**	**207.4**	**225.9**	**244.3**	**1,094.5**

(1) Straight-line depreciation is a method of calculating depreciation whereby an asset is expensed consistently throughout its useful life.

10.5.4 Operating expenditure

Our operating expenditure forecast is detailed in Chapter 5 Operating Expenditure and is summarised in Table 10.5.

Table 10.5 - Operating expenditure ($million nominal)

	2028	2029	2030	2031	2032	Total
Controllable operating expenditure and insurances	346.4	364.1	371.0	385.6	403.8	**1,870.9**
AEMO participant and cyber security fee	15.4	16.3	17.3	18.3	19.4	**86.7**
Debt raising costs	4.4	4.6	4.8	4.9	5.1	**23.7**
Total operating expenditure	**366.2**	**385.0**	**393.0**	**408.8**	**428.3**	**1,981.3**

10.5.5 Taxation

Our forecast for taxation, applying a value for imputation credits of 0.57 consistent with the AER's 2022 Rate of Return Instrument (refer Chapter 8 Rate of Return, Taxation and Inflation), is presented in Table 10.6.

Table 10.6 - Taxation ($million nominal)

	2028	2029	2030	2031	2032	Total
Corporate tax	53.6	48.6	41.7	44.3	42.0	**230.2**
Value of imputation credits	(30.6)	(27.7)	(23.8)	(25.2)	(24.0)	**(131.2)**
Taxation	**23.1**	**20.9**	**17.9**	**19.0**	**18.1**	**99.0**

10.5.6 Revenue adjustments

Any efficiency gains or losses arising from the EBSS and CESS in the 2022-27 regulatory period are carried over as an adjustment to the MAR in the 2027-32 regulatory period (referred to as a carryover amount).

Our approach to forecasting EBSS and CESS carryover amounts, and CESS true-up carryover, from the 2022-27 regulatory period is described in Chapter 13 Incentive Schemes, while the carryovers are summarised in Table 10.7.

Table 10.7 - EBSS and CESS carryover amounts ($million nominal)

	2028	2029	2030	2031	2032	Total
EBSS carryover	(81.8)	(78.1)	(54.3)	(23.0)	-	**(237.2)**
CESS carryover	(28.0)	(28.7)	(29.5)	(30.2)	(31.0)	**(147.4)**
CESS true-up for 2021/22	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	**(0.2)**
Total revenue adjustments	**(109.8)**	**(106.8)**	**(83.8)**	**(53.3)**	**(31.0)**	**(384.8)**

10.6 X-factors and smoothed revenue

We apply an X-factor to the unsmoothed revenue requirement to minimise revenue fluctuations and pricing impacts on consumers, in accordance with the Rules[179]. This smoothed revenue profile is the MAR that is used as the basis upon which our prescribed transmission prices are set each year[180].

Within the regulatory period, our MAR will be updated each year to reflect various factors including actual inflation, changes to the annual return on debt, and any approved cost pass through (refer Chapter 11 Pass Through Events) or contingent projects triggered during the regulatory control period (refer Chapter 4 Capital Expenditure and Appendix 4.04 Contingent Projects).

10.6.1 Revenue smoothing

We engaged with the Revenue Proposal Reference Group (RPRG) to ensure our approach to revenue smoothing was transparent and genuinely reflected customer interests. Through this process, we explored different options and put forward an alternative smoothing approach designed to balance revenue recovery with anticipated energy demand growth over the 2027-32 regulatory period, aiming to provide customers with a smoother, more predictable price path.

We empowered the RPRG to determine the approach to be included in our Revenue Proposal. The RPRG specifically supported this approach to revenue smoothing, and this now forms the basis of our revenue forecast in this 2027-32 Revenue Proposal. The resulting X-factors and smoothed revenue profile are shown in Table 10.8.

In the final year of the 2027-32 regulatory period, the smoothed revenue is 2.03% higher than the unsmoothed revenue, which is within the AER's 3% threshold[181].

[179] National Electricity Rules, clause 6A.6.8(c).
[180] The net present value of total revenue over the regulatory period is the same for the smoothed and unsmoothed revenue profiles.
[181] Final decision – Electricity transmission network service providers PTRM handbook, Australian Energy Regulator (AER), March 2025.

Table 10.8 - X-factors and smoothed MAR ($million nominal)

	2028	2029	2030	2031	2032	Total
Unsmoothed revenue requirement	1,025.0	1,043.8	1,111.6	1,208.6	1,313.0	**5,702.0**
X-factors	(2.54%)	(3.00%)	(4.25%)	(5.94%)	(7.38%)	
Smoothed MAR	**989.8**	**1,046.0**	**1,118.8**	**1,216.0**	**1,339.7**	**5,710.2**

10.7 Average indicative price path

Each year we calculate our annual prescribed transmission service charges consistent with our approved Pricing Methodology (refer Chapter 14 Pricing Methodology), which must comply with the requirements of the Rules and the AER's 2025 Transmission Pricing Methodology Guidelines[182].

Powerlink's contribution to the average Queensland electricity bill is currently estimated at 6.7% for households and 6.5% for small businesses[183]. This equates to approximately $148 per annum for residential customers[184] and $288 per annum for small businesses[185].

To provide the indicative impact of our Revenue Proposal on average transmission prices, we divide our forecast MAR by forecast energy delivered in Queensland in each year of the 2027-32 regulatory period. Based on our forecast smoothed revenue, the indicative impact on the transmission component of electricity bills in the first year of the next regulatory period (2027/28) would be:

- **Residential -** a nominal increase of $7 (5%), real increase of approximately $3 (2%).
- **Small business -** a nominal increase of $14 (5%), real increase of approximately $6 (2%).

For the remainder of the 2027-32 regulatory period, the transmission component of electricity bills is forecast to increase by approximately 5% each year in nominal terms[186].

The indicative impact of our forecast revenue on the transmission component of average annual electricity bills in each year of the 2027-32 regulatory period is shown in Table 10.9.

Table 10.9 - Indicative impact on transmission component of average annual electricity bills ($ nominal)

	2027	2028	2029	2030	2031	2032
Residential annual bill	148	155	163	171	179	188
Annual change		7	8	8	8	9
Small business	288	302	317	332	349	366
Annual change		14	15	15	16	17

182 Electricity Transmission Network Service Providers Pricing Methodology Guidelines, Australian Energy Regulator, July 2025.
183 Default Market Offer 2025-26 Final Determination, Australian Energy Regulator, May 2025; and 2025-26 Pricing Proposal Overview, Energex, May 2025.
184 Based on the AER's residential median energy usage of 4,600kWh per annum (May 2025).
185 Based on the AER's small business median energy usage of 10,000kWh per annum (May 2025).
186 Based on forecast energy delivered per AEMO's Electricity Statement of Opportunities 2025.

10.7.1 Other customer pricing impacts

Throughout our engagement, our customers and other stakeholders have emphasised the importance of transparency in cumulative customer pricing impacts. For example, the potential pricing impacts associated with Priority Transmission Investment (PTI) projects and contingent projects subject to a Contingent Project Application (CPA) in the current period, as these are subject to regulatory mechanisms outside the revenue determination process.

We have included an overview of these projects and an analysis of the potential pricing impacts in Appendix 10.01 Pricing Impact Scenarios.

11 Pass Through Events

11.1 Introduction

This chapter sets out the nominated and other pass through events proposed by Powerlink for the 2027-32 regulatory period. The pass through event mechanism in the National Electricity Rules (Rules) is intended to provide an efficient means for a network service provider to recover the efficient costs of uncontrollable material events that either cannot be insured or where the establishment of self-insurance is not economically viable.

Key highlights:

- We take a holistic approach to identify and manage our risks in the most cost-effective way for customers and Powerlink. We assess if and how risks can be efficiently mitigated through a balance of commercial insurance, self-insurance and pass through events.
- Having regard to the current insurance market, we nominate the following pass through events for the 2027-32 regulatory period:
    - Insurance coverage event
    - Insurer credit risk event
    - Natural disaster event, and
    - Terrorism event.
- We have proposed a $0 network alternative support allowance within our operating expenditure forecast (refer Chapter 5 Operating Expenditure) and will seek a pass through in the event that material network support costs are incurred within the period.

11.2 Regulatory requirements

The Rules[187] allow for the following pass through events:

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 for the determination.

The pass through event mechanism allows a TNSP to nominate additional pass through events as part of a Revenue Proposal, referred to as a nominated pass through event. In proposing nominated pass through events, we have had regard to the considerations set out in Chapter 10 of the Rules[188].

> *The nominated pass through event considerations are:*
>
> *(a) whether the event proposed is an event covered by a category of pass through event specified in clause 6.6.1(a1)(1) to(4) (in the case of a distribution determination) or clause 6A.7.3(a1)(1) to(4) (in the case of a transmission determination);*

[187] National Electricity Rules, clause 6A.7.3(a1).
[188] National Electricity Rules, Chapter 10, definition of *nominated pass through event considerations*.

(b) *whether the nature or type of event can be clearly identified at the time the determination is made for the service provider;*

(c) *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;*

(d) *whether the relevant service provider could insure against the event, having regard to:*

  (1) *the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or*

  (2) *whether the event can be self-insured on the basis that:*

    (i) *it is possible to calculate the self-insurance premium; and*

    (ii) *the potential cost to the relevant service provider would not have a significant impact on the service provider's ability to provide network services; and.*

(e) *any other matter the AER considers relevant and which the AER has notified Network Service Providers is a nominated pass through event consideration.*

We have provided information on how we consider each of the nominated pass through events meet these considerations in the following sections.

Pass through events can lead to an increase or decrease in costs (a positive or negative change event). The change in costs must exceed 1% of Maximum Allowed Revenue (MAR) in the relevant year before a Transmission Network Service Provider (TNSP) can seek a determination from the Australian Energy Regulator (AER) for pass through of those costs[189]. For Powerlink, based on the MAR forecast in our Revenue Proposal, this threshold would be approximately $10 million to $11 million.

11.3 Nominated pass through events

As identified above, the Rules allow a TNSP to nominate pass through events as part of a Revenue Proposal. The considerations for a nominated pass through event are defined in Chapter 10 of the Rules[190]. We have had regard to these considerations in the development of our nominated pass through events and have identified how we consider each nominated pass through satisfies these considerations in the following sections.

We take a holistic approach to the identification and management of our risks. We manage our risk profile with a suite of preventative, detective and mitigating controls. A key component of this strategy is the development and maintenance of an insurance program. To ensure an optimal balance of cover in the most cost-effective way for customers and Powerlink, we consider the complementary nature of commercial insurance coverage, self-insurance and pass through events. This holistic approach has guided the development of this Revenue Proposal.

Among the considerations that we must have regard to under the Rules for our nominated pass through events is the extent to which the event can be insured or self-insured[191].

We engaged our insurance broker, Marsh Pty Ltd (Marsh), to advise us on our insurance and risk management approach for the 2027-32 regulatory period, including any risks that may need to be addressed as a pass through

[189] National Electricity Rules, Chapter 10, definition of *materially*.
[190] National Electricity Rules, Chapter 10, definition of *nominated pass through event considerations*.
[191] National Electricity Rules, Chapter 10, definition of *nominated pass through event considerations*.

event (refer Appendix 5.06). Our proposed approach to insurance and self-insurance is addressed as part of our operating expenditure forecast (refer Chapter 5 Operating Expenditure).

Based on Marsh's advice, we propose the following nominated pass through events for the 2027-32 regulatory period:

- Insurance coverage event
- Insurer credit risk event
- Natural disaster event, and
- Terrorism event.

Powerlink proposed the first three events in its Revenue Proposal for the 2022-27 regulatory period. Marsh recommended an additional event given the increasing risk of act of terrorism events (refer Chapter 5 Operating Expenditure). This type of nominated pass through is common among other TNSPs and Distribution Network Service Providers (DNSPs) and has been accepted by the AER in other recent determinations[192].

The following sections set out our proposed definition and justification for each of these events. We consider that our nominated pass through events are consistent with the Rules[193].

11.3.1 Insurance coverage event

We propose an insurance coverage event to mitigate the risk of liability losses that exceed, and/or are not covered due to gaps in, our insurance coverage, for example, where there is a lack of coverage available, coverage is withdrawn or reasonable commercial terms cannot be secured.

We consider the nominated pass through event complies with the considerations set out in Chapter 10 of the Rules[194]:

- The proposed insurance coverage event is not a pass through event specified in the Rules[195].
- We consider that the nature and type of event can be clearly identified at the time the AER makes its determination.
- Liability events such as bushfire could result in losses that exceed the limit of cover on existing liability insurance policies. The occurrence of an insurance coverage event is not foreseeable, has a low probability of occurrence but a high cost impact. We cannot fully prevent these types of events from occurring, noting that while we invest, operate and maintain our network to withstand such events, we cannot substantially mitigate their cost impact.
- We have insurance coverage based on reasonable commercial terms and set our insurance limits based on credible risk-based scenario analysis, worst or maximum foreseeable loss studies and professional insurance broker advice. We consider it would not be efficient to obtain additional insurance beyond a prudent, risk-based limit of cover.
- We cannot control movements and insurer appetite in the insurance liability market, where those movements mean that it is no longer possible to take out an insurance policy (or set of insurance policies) at all or in part, or on reasonable commercial terms.

[192] Final Decisions for Energex (2025), Ergon Energy (2025), TasNetworks (2024), TransGrid (2023) and ElectraNet (2023), AusNet Services transmission (2022).
[193] National Electricity Rules, Chapter 10, definition of *nominated pass through event considerations*.
[194] National Electricity Rules, Chapter 10, definition of *nominated pass through event considerations*.
[195] National Electricity Rules, Clause 6A.7.3(a1).

- It would also be inefficient to seek an additional self-insurance allowance as such a reserve may need to be maintained for a significant period of time, noting that in practice it may never be required.

Our proposed definition for this event is shown in Table 11.1.

Table 11.1 - Proposed definition of insurance coverage event

An Insurance Coverage Event occurs if:

6. Powerlink:
    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
7. Powerlink incurs costs:
    a. beyond a relevant policy limit for that policy or set of insurance policies; or
    b. that are unrecoverable under that policy or set of insurance policies due to changed circumstances; and
8. The costs referred to in paragraph 2 above materially increase the costs to Powerlink in providing prescribed transmission services.

For the purposes of this insurance coverage event:

- 'changed circumstances' means movements in the relevant insurance liability market that are beyond the control of Powerlink, where those movements mean that it is no longer possible for Powerlink to take out an insurance policy or set of insurance policies at all or on reasonable commercial terms that include some or all of the costs referred to in paragraph 2 above within the scope of that insurance policy or set of insurance policies.
- 'costs' means the costs that would have been recovered under the insurance policy or set of insurance policies had:
    i. the limit not been exhausted; or
    ii. those costs not been unrecoverable due to changed circumstances.
- A 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 Powerlink was regulated; and
- Powerlink 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 Powerlink in relation to any aspect of Powerlink's network or business; and
- Powerlink 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 Powerlink in relation to any aspect of Powerlink's network or business.

Note for the avoidance of doubt, in assessing an insurance coverage event through application under Clause 6A.7.3 of the Rules, the AER will have regard to:

- The relevant insurance policy or set of insurance policies for the event;
- The level of insurance that an efficient and prudent Network Service Provider (NSP) would obtain, or would have sought to obtain, in respect of the event; and
- Any information provided by Powerlink to the AER about Powerlink's actions and processes; and
- Any guidance published by the AER on matters the AER will likely have regard to in assessing any insurance coverage event that occurs.

11.3.2 Insurer credit risk event

We propose an insurer credit risk event would be triggered where an insurer becomes insolvent and Powerlink is consequently subject to additional costs than allowed under the insurance policy with that insurer.

We consider the nominated pass through event complies with the considerations set out in the Rules[196]:

- The proposed insurer credit risk event is not a pass through event specified in the Rules[197].
- We consider that the nature and type of event can be clearly identified at the time the AER makes its determination.
- We set minimum requirements for the credit rating of participating underwriters and apportion our policies across domestic and international providers. This combination provides a level of risk mitigation against a potential Insurer Credit Risk event. However, we are not able to control whether one or more of our insurers become insolvent.
- We cannot obtain insurance on reasonable commercial terms to cover the occurrence of this type of event. In addition, we are not able to calculate a reasonable self-insurance premium for this event as it would be relative to the claim for a risk that was insured by the insolvent insurer.

Our proposed definition for this event is shown in Table 11.2.

Table 11.2 - Proposed definition of insurer credit risk event

An Insurer Credit Risk event occurs if:

- An insurer of Powerlink becomes insolvent, and as a result, in respect of an existing or potential claim for a risk that was insured by the insolvent insurer, Powerlink:
  - 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
  - incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer.

Note: In assessing an Insurer Credit Risk event pass through application, the AER will have regard to, amongst other things:

- Powerlink's attempts to mitigate and prevent the event from occurring by reviewing and considering the insurer’s track record, size, credit rating and reputation; and
- in the event that a claim would have been covered by the insolvent insurer’s policy, whether Powerlink had reasonable opportunity to insure the risk with a different insurer.

11.3.3 Natural disaster event

We propose a natural disaster risk event would be triggered where we could not obtain insurance coverage on reasonable commercial terms and the disaster caused a material increase in costs to Powerlink.

We consider the nominated pass through event complies with the considerations set out in the Rules[198]:

- The proposed natural disaster risk event is not a pass through event specified in the Rules[199].
- We consider that the nature and type of event can be clearly identified at the time the AER makes its determination.

[196] National Electricity Rules, Chapter 10, definition of *nominated pass through event considerations*.
[197] National Electricity Rules, Clause 6A.7.3(a1).
[198] National Electricity Rules, Chapter 10, definition of *nominated pass through event considerations*.
[199] National Electricity Rules, Clause 6A.7.3(a1).

- Natural disaster events, by definition, cannot be prevented or avoided. We employ a range of strategies to minimise and mitigate the exposure of the transmission network to natural disasters. These include a broad range of technical preventative measures, such as asset siting and design, continuous asset monitoring and maintenance activities along with existing insurance cover. Given the potential increase in natural catastrophe event frequency and intensity, and subsequent premium changes, we consider it prudent to continue to review the level of insurance coverage, deductibles and limits over the 2027-32 regulatory period.
- Movements in the insurance market may result in situations where it is no longer possible to take out an insurance policy, (or a set of insurance policies) at all, or to do so on reasonable commercial terms. This is particularly relevant for Towers and Lines insurance, which is a bespoke product with few insurers in the insurance market offering coverage.
- To manage this risk, we consider it prudent and efficient to optimise our level of insurance coverage supported by both self-insurance and a natural disaster event pass through.

Our proposed definition for this event is shown in Table 11.3.

Table 11.3 - Proposed definition of natural disaster risk event

Natural Disaster event means any natural disaster including but not limited to cyclone, fire, flood or earthquake that occurs during the 2027-32 regulatory control period that changes the costs to Powerlink in providing prescribed transmission services, provided the fire, flood or other event was:

- a consequence of an act or omission that was necessary for Powerlink to comply with a regulatory obligation or requirement or with an applicable regulatory instrument; or
- not a consequence of any other act or omission of Powerlink.

Note: In assessing a natural disaster event pass through application, the AER will have regard to, amongst other things:

- whether Powerlink has insurance against the event; and
- the level of insurance that an efficient and prudent NSP would obtain in respect of the event.

11.3.4 Terrorism event

We propose a terrorism risk event would be triggered where an unforeseen act of terrorism for which Powerlink did not have insurance against caused a material increase in costs to Powerlink.

We consider the nominated pass through event complies with the considerations set out in the Rules[200]:

- The proposed terrorism risk event is not a pass through event specified in the Rules[201].
- We consider that the nature and type of event can be clearly identified at the time the AER makes its determination.
- Terrorism events are unpredictable and cannot be prevented or avoided. We employ a range of strategies to minimise and mitigate the exposure of the transmission network to terrorism, including actions we take to ensure the physical and electronic (cyber) security of our transmission network. While these actions assist to withstand such events, an act of terrorism could significantly impact on the cost of maintaining or restoring reliable supply of our prescribed transmission services.

[200] National Electricity Rules, Chapter 10, definition of *nominated pass through event considerations*.
[201] National Electricity Rules, Clause 6A.7.3(a1).

- The low frequency and potentially very high costs of a terrorism event make it challenging to insure against such events, with many insurers excluding or limiting cover. Whilst a level of terrorism insurance is currently in place, the cover provided and how it would respond to an event is uncertain. Terrorism insurance options are subject to ongoing review and analysis and general insurer appetite in underwriting this type of cover is reducing, with very limited alternative options which will impact its ongoing commercial viability. In addition, we are not able to calculate a reasonable self-insurance premium for this event.

Our proposed definition for this event is shown in Table 11.4.

Table 11.4 - Proposed definition of terrorism event

Terrorism event means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which:

- from its nature or context is 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
- changes the costs to Powerlink in providing prescribed transmission services.

Note: In assessing a terrorism event pass through application, the AER will have regard to, amongst other things:

- whether Powerlink has insurance against the event;
- the level of insurance that an efficient and prudent NSP would obtain in respect of the event; and
- whether a declaration has been made by a relevant government authority that a terrorism event has occurred.

11.4 Network support pass through

We may be required to make a payment to a generator or other entity for the provision of network support services during the 2027-32 regulatory period.

Under the Rules[202], we can seek a determination from the AER for a pass through of any differences in costs between the amount included in the annual revenue requirement and actual efficient costs associated with network support events.

Given the inherent uncertainty in the need for such services, we have proposed a $0 network alternative support allowance for the 2027-32 regulatory period and will estimate annual system security network support payments in accordance with the Rules. If network alternative support is required and can be justified within the period, we will seek a network support pass through from the AER at that time (refer Chapter 5 Operating Expenditure).

[202] National Electricity Rules, Clause 6A.7.2.

12 Shared Assets

12.1 Introduction

Shared assets are used to provide prescribed transmission services and either non-regulated transmission services or services that are not transmission services[203]. The assets may be fixed (e.g. poles), mobile (e.g. vehicles) or non-physical (e.g. radio frequency spectrum).

This chapter sets out Powerlink's assessment of our forecast unregulated revenues from shared assets for the 2027-32 regulatory period. The purpose of this assessment is to determine whether any adjustment is required to our proposed annual revenue requirement.

Key highlights:

- Shared Asset Unregulated Revenues for the 2027-32 regulatory period have been assessed as not material, based on the approach in the Australian Energy Regulator's Shared Asset Guidelines.
- We have not adjusted our proposed annual revenues in our Revenue Proposal.

12.2 Regulatory requirements

The National Electricity Rules (Rules)[204] allow the Australian Energy Regulator (AER) to reduce a Transmission Network Service Provider's (TNSP's) annual revenue requirement to reflect the costs attributable to services which generate unregulated revenues. The AER's approach to making an adjustment to revenue is set out in its Shared Asset Guidelines (SA Guidelines)[205].

The SA Guidelines sets out the following process to establish the shared asset cost reduction for each year of the regulatory period:

- determine the Shared Asset Unregulated Revenues (SAUR)
- determine whether the SAUR is material (i.e. exceeds 1% of the proposed annual revenue requirement)
- where the SAUR is material, calculate the shared asset cost reduction (equal to 10% of the SAUR), subject to:
    - application of the control step (i.e. a cap) and/or
    - adjustments for contributed assets, if any.

Where the SAUR is not material, no further action is required.

Materiality and the unregulated revenue relevant to cost reductions are determined by averaging the forecast SAUR over the 2027-32 regulatory period. Where the SAUR is material, the SA Guidelines allows for TNSPs to propose an alternative method to calculate a cost reduction. The TNSP must demonstrate that customers would be no worse off compared to the SA Guidelines approach.

Where assets provide prescribed transmission services and unregulated services consistent with a TNSP's Cost Allocation Methodology, the shared asset mechanism does not apply.

[203] National Electricity Rules, clause 6A.5.5.
[204] National Electricity Rules, clause 6A.5.5.
[205] Shared Asset Guidelines (version 2), Australian Energy Regulator, June 2025.

12.3 Shared assets assessment

Our assessment shows the unregulated use of shared assets is not forecast to be material (i.e. remains under the 1% materiality threshold) in any year of the 2027-32 regulatory period, as shown in Table 12.1. As a result, we propose no adjustment to our annual revenues in our Revenue Proposal.

Table 12.1 - Materiality assessment ($million nominal)

	2028	2029	2030	2031	2032	Total
Proposed smoothed Maximum Allowed Revenue (MAR)	989.8	1,046.0	1,118.8	1,216.0	1,339.7	5,710.2
1% of smoothed MAR	9.9	10.5	11.2	12.2	13.4	57.1
Average annual SAUR	3.9	3.9	3.9	3.9	3.9	19.5
SAUR as % MAR	0.4%	0.4%	0.3%	0.3%	0.3%	
Exceed 1% Materiality Test	**No**	**No**	**No**	**No**	**No**	

12.4 Our approach

We have applied the AER's approach outlined in Section 12.2 to determine whether a revenue adjustment should be applied. We have adopted the same methodology to estimate our SAUR as applied in our previous 2023-27 Revenue Proposal.

12.4.1 Shared asset unregulated revenues

We have identified non-regulated services that use shared assets and are applicable to the shared assets mechanism in the 2027-32 regulatory period. These are:

- **Property rentals –** rental income from our land or buildings, either acquired for or incidental to the development of our prescribed transmission network.
- **Tower access –** provision of space for the co-location of mobile phone carriers' equipment on our transmission and communications towers.
- **QDATA –** commercial data service offering network-related information for the Queensland region.
- **Property searches –** provision of information to help applicants determine whether Powerlink holds any assets or interests in relation to specified land parcels.
- **Easement compensation –** compensation received from non-regulated customers for the right to access, construct and maintain transmission lines on Powerlink's regulated substation land during the term of their Connection and Access Agreement.

Our forecast of SAUR for each of these services and in total is shown in Table 12.2.

Table 12.2 - Forecast SAUR ($million nominal)

	2028	2029	2030	2031	2032	Total
Property rentals	0.6	0.6	0.6	0.6	0.6	**2.9**
Tower access	1.9	1.9	2.0	2.0	2.1	**9.8**
QDATA	0.1	0.1	0.1	0.1	0.1	**0.3**
Property searches	0.2	0.2	0.2	0.2	0.2	**1.1**
Easement compensation	1.0	1.1	1.1	1.1	1.1	**5.4**
Total	**3.7**	**3.8**	**3.9**	**4.0**	**4.1**	**19.5**

12.4.2 Materiality

The SA Guidelines state that SAUR will be considered material when the average for the period is greater than 1% of the total smoothed revenue requirement for that regulatory year.

Our unregulated use of shared assets applicable to the shared assets mechanism in the 2027-32 regulatory period is not forecast to exceed the 1% materiality threshold in any year. As a result, no revenue adjustment has been applied.

13 Incentive Schemes

13.1 Introduction

This chapter outlines net carryover amounts from incentive schemes in the current 2022-27 regulatory period, and Powerlink's proposed targets for the Efficiency Benefit Sharing Scheme (EBSS) and the Capital Expenditure Sharing Scheme (CESS) for the 2027-32 regulatory period, for operating and capital expenditure respectively.

This chapter also outlines Powerlink's performance under the Service Target Performance Incentive Scheme (STPIS) in the current 2022-27 regulatory period, as well as our proposed STPIS values and targets for the 2027-32 regulatory period. The chapter also addresses our approach in respect to the Demand Management Innovation Allowance Mechanism (DMIAM).

Key highlights:

- Under the EBSS, we estimate a net negative carryover amount from the 2022-27 regulatory period of $225.0 million ($ real, 2026/27), which will reduce the Maximum Allowed Revenue (MAR) for the 2027-32 regulatory period.
- We propose that $1,730.2 million ($ real, 2026/27) of our forecast operating expenditure for the 2027-32 regulatory period be subject to the EBSS.
- Under the CESS, we estimate a net negative carryover amount from the 2022-27 regulatory period of $136.4 million ($ real, 2026/27) and a CESS true-up for 2021/22 of negative $0.1 million ($ real, 2026/27), which will reduce the MAR for the 2027-32 regulatory period.
- We propose that $2,484.5 million ($ real, 2026/27) of our forecast capital expenditure for the 2027-32 regulatory period be subject to the CESS.
- Under the STPIS, we have maintained or improved our STPIS network performance for the current 2022-27 regulatory period and we continue to manage market impacts by applying prudent measures and behaviours.
    - Our Market Impact Component (MIC) performance has been impacted by factors largely outside our control.
    - We propose Service Component (SC) targets consistent with the Australian Energy Regulator's (AER's) historical data ranges.
- We will not seek a DMIAM allowance for the 2027-32 regulatory period.

13.2 Regulatory requirements

In its Final Decision for our 2022-27 revenue determination, the AER applied version 2 (November 2013) of the EBSS, and the CESS as set out in version 1 (November 2013) of the Capital Expenditure Incentive Guideline[206].

In its Framework and Approach paper for Powerlink[207], the AER states that it intends to continue to apply the EBSS for our 2027-32 regulatory period, but will confirm this approach in its Final Decision, and that it will apply the CESS as set out in the updated Capital Expenditure Incentive Guideline as published in August 2025.

[206] Final decision Powerlink Queensland transmission determination 2022 to 2027, Australian Energy Regulator, April 2022, pages 63-64.
[207] Framework and approach Powerlink transmission determination 2027-32, Australian Energy Regulator, July 2025, pages 3-5.

We have calculated net carryover amounts from the 2022-27 regulatory period and set our EBSS and CESS targets for the 2027-32 regulatory period consistent with the relevant incentive schemes identified above.

The Rules[208] require that Powerlink include proposed values for the STPIS parameters as part of our Revenue Proposal. For the current 2022-27 regulatory period, we are subject to version 5 of the STPIS (October 2015). The AER, in its Framework and Approach paper for Powerlink[209], confirmed that it will apply version 6 of the STPIS (April 2025) for the 2027-32 regulatory period.

13.3 Efficiency Benefit Sharing Scheme

The EBSS is intended to provide a continuous incentive for network service providers to pursue efficiency improvements in operating and maintenance expenditure.

13.3.1 Carryover amount from the 2022-27 regulatory period

Under the EBSS, our MAR for the 2027-32 regulatory period is adjusted for approximately 30% of any operating expenditure efficiency gain or loss accrued during the 2022-27 regulatory period[210] (the carryover amount). Our total EBSS carryover amount from the 2022-27 regulatory period is estimated as $225.0 million (negative), as shown in Table 13.1.

Table 13.1 - EBSS carryover amount ($million real, 2026/27)

	2028	2029	2030	2031	2032	Total
EBSS carryover	(79.8)	(74.2)	(50.3)	(20.8)	-	(225.0)

Our calculated EBSS carryover is based on the difference between our actual/forecast operating expenditure and the AER allowance (target for the purpose of the EBSS) for the first three years of the 2022-27 regulatory period and an estimate of that difference for the last two years (2025/26 and 2026/27).

The approved network support cost pass throughs for 2022/23 to 2024/25 have been included in the total operating expenditure allowance. We have also adjusted our forecast and actual operating expenditure in each year of the 2022-27 regulatory period for inflation and approved excludable costs, including debt raising costs and network support costs.

Movements in provisions related to operating expenditure of $20.1 million have also been excluded from actual operating expenditure in years 2022/23 to 2024/25 in the EBSS model, consistent with advice provided by the AER.

[208] National Electricity Rules, Schedule 6A.1, clause S6A.1.3(2).
[209] Framework and approach Powerlink transmission determination 2027-32, Australian Energy Regulator, July 2025, p.5.
[210] Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, Australian Energy Regulator, November 2013, Section 1.3.

13.3.2 EBSS target for the 2027-32 regulatory period

Our EBSS target for the 2027-32 regulatory period is $1,730.2 million, comprising our operating expenditure forecast less category specific expenditure, as shown in Table 13.2.

Table 13.2 - EBSS target ($million real, 2026/27)

	2028	2029	2030	2031	2032	Total
Operating expenditure forecast	356.9	365.8	363.9	368.9	376.7	**1,832.2**
Less excluded costs						
Debt raising costs	4.3	4.3	4.4	4.4	4.5	**22.0**
Network support costs	-	-	-	-	-	**-**
AEMO participant and cyber security fees	15.0	15.5	16.0	16.5	17.0	**80.1**
EBSS target	**337.6**	**345.9**	**343.5**	**347.9**	**355.2**	**1,730.2**

13.4 Capital Expenditure Sharing Scheme

13.4.1 Carryover amount from the 2022-27 regulatory period

As with the EBSS, the CESS requires that we adjust our MAR for the 2027-32 regulatory period for our share (30%) of any capital expenditure efficiency gain or loss from the 2022-27 regulatory period (the carryover amount). Our total CESS carryover amount from the 2022-27 regulatory period is estimated as $136.4 million (negative), shown in Table 13.3.

Table 13.3 - CESS carryover amount ($million real, 2026/27)

	2028	2029	2030	2031	2032	Total
CESS carryover	(27.3)	(27.3)	(27.3)	(27.3)	(27.3)	**(136.4)**

This calculation is based on the difference between our actual/forecast capital expenditure and the AER allowance (target for the purpose of the CESS) for the first three years of the 2022-27 regulatory period and an estimate of that difference for the last two forecast years (2025/26 and 2026/27).

We have also adjusted our forecast and actual capital expenditure in each year of the 2022-27 regulatory period for inflation.

In our draft Revenue Proposal, published in September 2025, we proposed an alternative approach to the calculation of net carryovers under the CESS. This was to reflect the unprecedented increases in the costs of major plant items, materials and skilled resources experienced during the 2022-27 regulatory period, which were outside Powerlink’s control (refer Chapter 2 Operating Environment). However, following feedback from the AER and the Revenue Proposal Reference Group (RPRG), we have adopted the AER’s standard CESS methodology in calculating the net carryover consistent with version 1 (November 2013) of the Capital Expenditure Incentive Guideline.

13.4.2 CESS true-up for 2021/22 actuals

The CESS true-up requires that we adjust our MAR for the last year of the previous 2017-22 regulatory period (2021/22) to account for any difference between the forecast and actual capital expenditure. Our total CESS true-up amount from the 2017-22 regulatory period is $0.1 million (negative), shown in Table 13.4.

Table 13.4 - CESS true-up ($million real, 2026/27)

	2028	2029	2030	2031	2032	Total
CESS true-up	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	**(0.1)**

13.4.3 CESS target for the 2027-32 regulatory period

Our CESS target for the 2027-32 regulatory period is $2,484.5 million, comprising our capital expenditure forecast net of disposals less movements in provisions, as shown in Table 13.5.

Table 13.5 - CESS target ($million real, 2026/27)

	2028	2029	2030	2031	2032	Total
Capital expenditure forecast (net of disposals)	516.3	503.5	428.3	535.4	516.0	**2,499.5**
Adjustments						
Movement in provisions	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	**(15.0)**
CESS target	**513.3**	**500.5**	**425.3**	**532.4**	**513.0**	**2,484.5**

Adjustments may be made during the 2027-32 regulatory period for any capital expenditure approved by the AER for contingent projects that are triggered during the period. Our proposed contingent projects are outlined in our capital expenditure forecast (refer Chapter 4 Capital Expenditure).

13.5 Service Target Performance Incentive Scheme

13.5.1 Outcomes for the 2022-27 regulatory period

The three components to the STPIS are the Service Component (SC), Market Impact Component (MIC) and Network Capability Component (NCC).

While our STPIS performance demonstrates continued improvement, MIC performance has been adversely impacted by factors largely outside of our control as acknowledged in the transmission STPIS review[211] and in the AER's Final Decision on its 2025 STPIS (version 6)[212]. Key factors include the move towards geographically dispersed, weather-dependent generation and significant transmission investment to integrate new generation and storage, which has led to more planned outages and introduced considerable complexity in outage scheduling, which reduces the ability to minimise market impacts. Our STPIS outcomes for the SC, MIC and NCC for the current 2022-27 regulatory period are summarised in Table 13.6.

STPIS operates and data is reported to the AER on a calendar year basis. As our current regulatory period commenced on 1 July 2022, the information below reflects performance for the second half of that year. The AER's 2015 STPIS requires that a two-year rolling average be used to report the SC performance of the unplanned outage circuit event rate and average outage duration.

[211] Electricity transmission network service providers service target performance incentive scheme final amendments explanatory statement, Australian Energy Regulator, April 2025, page 11.
[212] Electricity transmission network service provider Service target performance incentive scheme version 6, Australian Energy Regulator, April 2025.

Table 13.6 - Historical STPIS annual compliance performance 2022 2H to 2025

Parameter	Unit of Measure	2022-27 Annual Target	Calendar Year 2022 2H	2023	2024	2025[3]
Service Component						
Unplanned outage circuit event rate [1]						
Lines Event Rate – Fault	Rate	17.03	7.39	7.59	9.15	11.73
Transformer Event Rate – Fault	Rate	16.81	9.06	12.31	12.44	19.49
Reactive Plant Event Rate – Fault	Rate	25.65	15.04	19.55	20.61	19.78
Lines Event Rate – Forced	Rate	17.02	8.56	11.38	11.11	12.70
Transformer Event Rate – Forced	Rate	14.82	9.36	12.03	10.64	12.00
Reactive Plant Event Rate – Forced	Rate	21.21	17.67	24.44	23.24	23.51
Loss of supply event frequency						
Loss of supply events > 0.05 (x) system minutes	Count	2	1	2	0	1
Loss of supply events > 0.40 (y) system minutes	Count	0	0	1	0	0
Average outage duration [1]						
Average outage duration	Minutes	33.23	69	323	46	79
Proper operation of equipment [2]						
Failure of protection system	Number	26	9	20	21	24
Material failure of Supervisory Control and Data Acquisition (SCADA) system	Number	1	0	0	0	1
Incorrect operational isolation of primary or secondary equipment	Number	4	1	2	5	4
Market Impact Component						
MIC	No. of Dispatch Intervals (DI)	1,001	3,619	2,239	667	2,295
Network Capability Component						
Network Capability Incentive Parameter Action Plan (NCIPAP)	No NCIPAP projects were proposed by Powerlink for the 2022-27 regulatory period.					

(1) Two year rolling average performance is reported as required by the AER's 2015 STPIS.
(2) Report only parameter with no weighting.
(3) The 2025 result is subject to the AER's review and approval of Powerlink's 2025 STPIS report.

13.5.2 STPIS target setting for the 2027-32 regulatory period

13.5.2.1 Market Impact Component and Network Capability Component

STPIS (version 6) suspends the application of the MIC. Hence, Powerlink is not required to propose MIC targets for the 2027-32 regulatory period.

Similarly, this version of the STPIS requires that proposed priority projects under the NCC are identified in a transmission business' Transmission Annual Planning Report (TAPR) and proposed for the AER's approval in its annual STPIS compliance review report. We have not identified any proposed priority projects in this Revenue Proposal.

13.5.2.2 Service Component

This section sets out our proposed SC values and the approach we used to set our targets for the 2027-32 regulatory period. This is based on the AER's 2025 STPIS, the AER's Framework and Approach paper for Powerlink's 2027-32 revenue determination[213] and the Regulatory Information Notice (RIN) issued to Powerlink by the AER for the purpose of this Revenue Proposal (the Reset RIN).

The Reset RIN defines the historical calendar years to be used to calculate our SC values for the 2027-32 regulatory period, for use in our Revenue Proposal and Revised Revenue Proposal. The year ranges that we must use to calculate SC values are 2020-2024 for our Revenue Proposal and 2021-2025 for our Revised Revenue Proposal[214].

The approach we used to set our STPIS targets is as follows:

- We have proposed targets, caps and floors for relevant parameters and sub-parameters related to the SC based on Section 3.2 of the AER's 2025 STPIS.
- The caps and floors were calculated based on a best fit statistical distribution to the previous five years performance data for each of the parameters and sub-parameters. The caps and floors reflect the 5th and 95th percentiles of each of the chosen statistical distributions. The methodology we applied to determine the statistical distributions for each parameter and sub-parameter is provided as Appendix 13.01 Setting STPIS Values.

The proper operation of equipment parameter is 'report only' and therefore no values are required. We do not address this further in this Revenue Proposal.

We have provided our STPIS SC values for the 2027-32 regulatory period based on the historical date ranges required by the AER in Table 13.7.

[213] Framework and approach Powerlink transmission determination 2027-32, Australian Energy Regulator, July 2025, p.5.
[214] 2027-32 Reset RIN for Powerlink Appendix A - Regulatory template instructions, Australian Energy Regulator, 9 October 2025 (as varied 28 November 2025), page 10.

Table 13.7 - STPIS values for 2027-32 regulatory period

SC Parameter (±1.25% MAR)	Floor	Target	Cap	Distribution
Unplanned outage circuit event rate (±0.75% MAR)				
Lines Event Rate – Fault	11.74	9.35	6.52	Weibull
Transformer Event Rate – Fault	15.03	12.45	10.25	Pearson5
Reactive Plant Event Rate – Fault	24.27	20.72	16.45	Weibull
Lines Event Rate – Forced	17.61	12.96	9.34	Pearson5
Transformer Event Rate – Forced	19.31	13.12	7.98	Gamma
Reactive Plant Event Rate – Forced	27.91	22.83	18.18	Gamma
Loss of supply event frequency (±0.30% MAR)				
Greater than 0.05 System Minutes (x)	4	1.40	0	Poisson
Greater than 0.40 System Minutes (y)	2	0.60	0	Poisson
Average outage duration (±0.20% MAR)				
Average outage duration	297.24	161.16	13.20	Log-logistic

13.5.3 STPIS Service Component historical performance informing targets

The following sections outline our historical performance for the SC, which informs our caps, floors and targets for each relevant parameter and sub-parameter.

The proposed targets outlined in Table 13.7 have been calculated using the year ranges required by the Reset RIN, i.e. 2020 to 2024, as presented in Figure 13.1 to Figure 13.9. Preliminary data for the 2025 calendar year has been included for information. The confirmed 2025 data will be used to calculate the targets in our Revised Revenue Proposal.

13.5.3.1 SC - Unplanned outage circuit event rate – fault

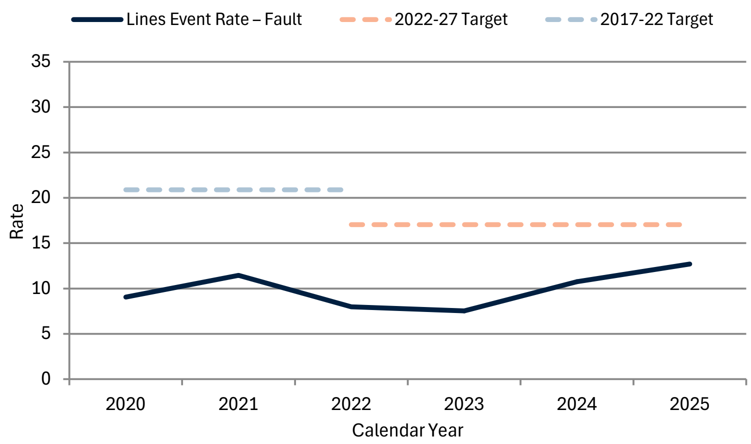
A fault outage is any element outage that occurred due to an element being switched off (such as circuit breakers) unexpectedly, i.e. it did not occur as a result of intentional manual operation of switching devices. The fault outage circuit event rate parameter measures network reliability based on an aggregate number of fault outages per annum for each of the element transmission types: lines, transformers and reactive plant.

To minimise the impact on our customers and the market, we rapidly respond to and restore fault outages on our network.

Deterioration in asset condition can contribute to fault outage events. Where prudent and efficient, we refurbish our deteriorating assets. This can restore asset performance, reduce fault level outage occurrences, and improve the overall reliability for our customers.

The historical performance of our fault outage circuit event rates since 2020 for transmission lines, transformers and reactive plant against their respective target is shown in Figures 13.1, 13.2 and 13.3.

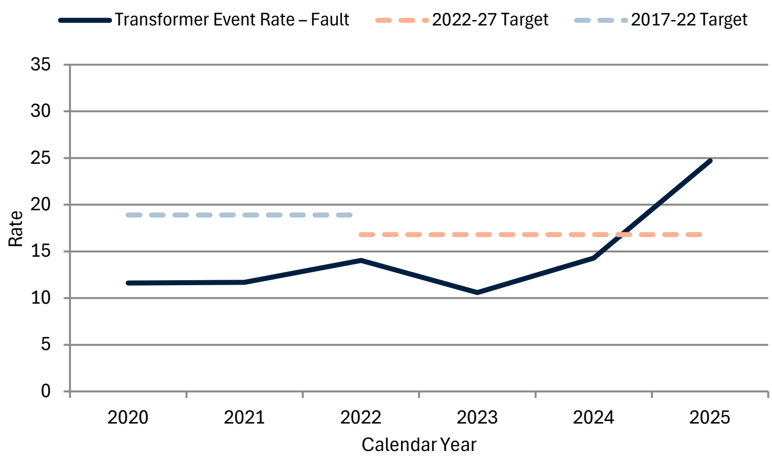
Figure 13.1 - Lines Event Rate – Fault 2020-2025



The lines fault event rate performed better than the target.

Outcomes remained within expected ranges based on long-term trends and is consistent with annual environmental and equipment performance variabilities and volatilities.

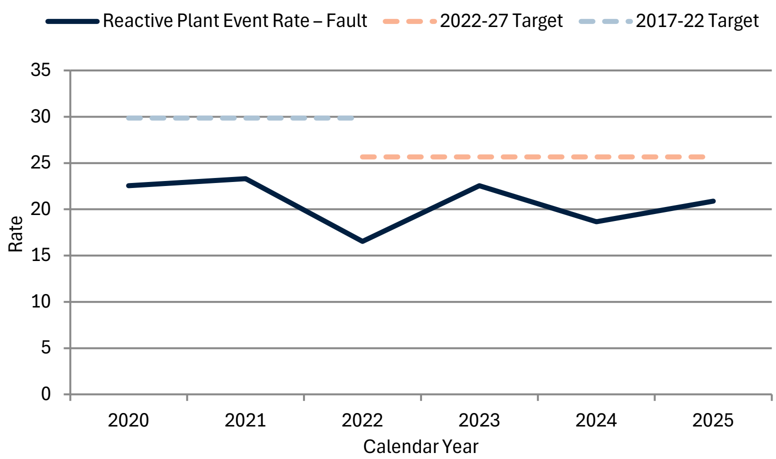
Figure 13.2 - Transformer Event Rate – Fault 2020-2025



The transformer fault event rate performed better than the target between 2020 and 2024.

Outcomes generally remained within expected ranges based on long-term trends and is consistent with annual environmental and equipment performance variabilities and volatilities. The 2025 year was an outlier due to an abnormally high repetition of events associated with a small number of specific assets due to both plant and equipment impacts.

Figure 13.3 - Reactive Plant Event Rate – Fault 2020-2025



The reactive plant fault event rate performed consistently better than the target due to less equipment and environmental related fault impacts.

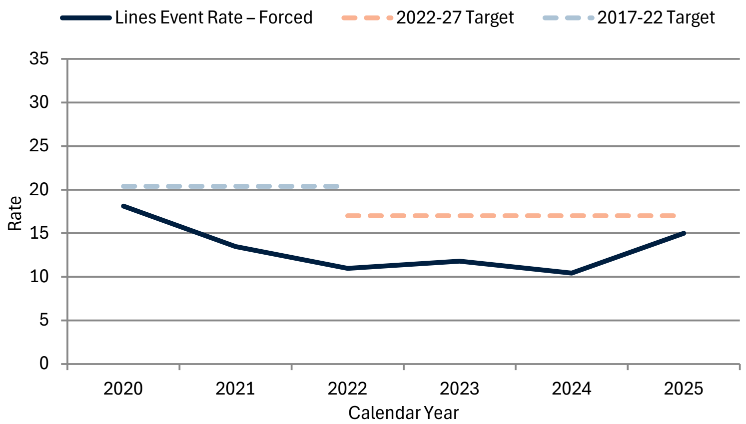
13.5.3.2 SC - Unplanned outage circuit event rate - forced

A forced outage is any element outage that occurred due to intentional manual operation of switching devices based on the requirement to undertake urgent and unplanned corrective activity, where less than 24 hours' notice was given to the affected customer(s) and/or AEMO.

Similar to the fault outage rate, the forced outage circuit event rate parameter measures network reliability based on an aggregate number of forced outages per annum for each of the element transmission types (lines, transformers and reactive plant).

The historical performance of our forced outage circuit rates since 2020 for transmission lines, transformers and reactive plant is shown in Figures 13.4, 13.5 and 13.6.

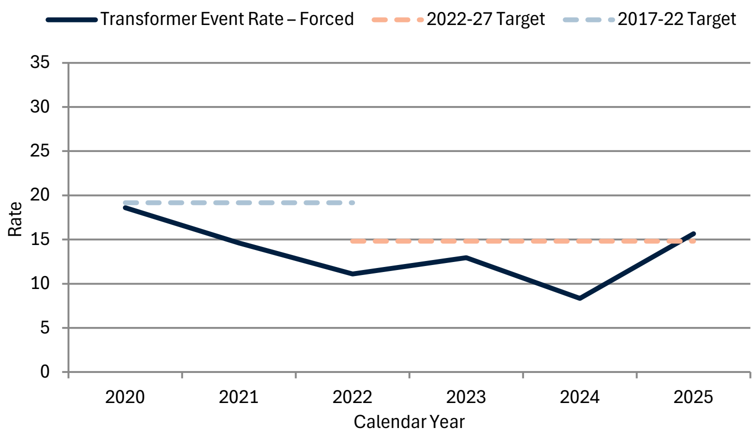
Figure 13.4 - Lines Event Rate – Forced 2020-2025



The lines forced event rate performed consistently better than the target.

Outcomes remained within expected ranges based on long-term trends and is consistent with annual environmental and equipment performance variabilities and volatilities.

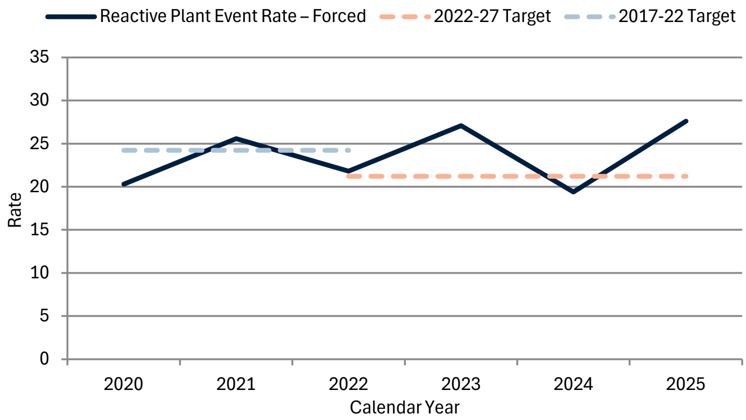
Figure 13.5 - Transformer Event Rate – Forced 2020-2025



The transformer forced event rate performed better than the target between 2020 and 2024.

Outcomes generally remained within expected ranges based on long-term trends and is consistent with annual environmental and equipment performance variabilities and volatilities. A step increase in the number of impacts to transformers occurred in 2025 due to instrument transformer and connection equipment related faults.

Figure 13.6 - Reactive Plant Event Rate – Forced 2020-2025



The reactive plant forced event rate performed consistently and broadly around the target across the five-year period.

The 2023 and 2025 results were influenced by opportunistic corrective work undertaken when operational conditions allowed. With alternative reactive plant available, activities such as weed removal, alarm investigations, and gas top-ups could be carried out cost-effectively without affecting network operations.

13.5.3.3 SC - Loss of supply event frequency

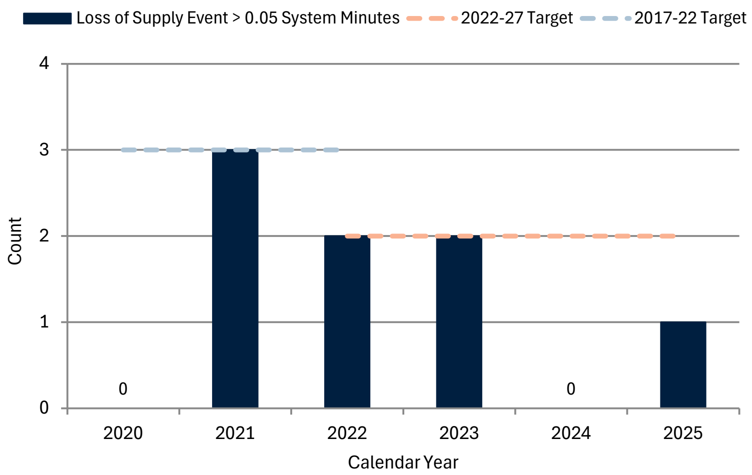
We report performance against two loss of supply event targets based on the thresholds specified in the AER's 2015 STPIS:

- the 'moderate' event (x) threshold is a loss of supply event greater than 0.05 system minutes, and
- the 'large' event (y) threshold is a loss of supply event greater than 0.40 system minutes.

13.5.3.4 SC - Loss of supply event frequency greater than 0.05 system minutes (x)

Our historical performance for the loss of supply event frequency greater than 0.05 system minutes parameter is shown in Figure 13.7.

Figure 13.7 - Loss of supply event frequency greater than 0.05 system minutes (x) 2020-2025



For the loss of supply event frequency sub-parameter under the 'moderate' (x) threshold, we met or performed better than the target.

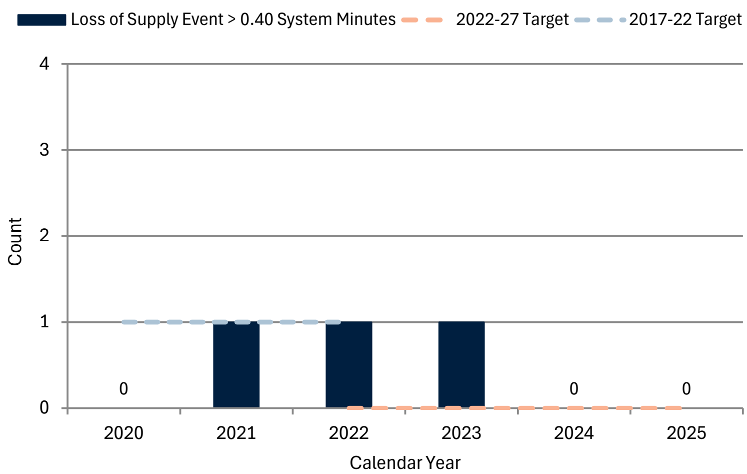
In 2022, the two events comprised de-energisation of two 110kV feeders in Brisbane to manage safety issues due to rising flood water, and a wildlife event in northern Queensland.

In 2023, there were two events – one due to plant failure and the other due to wildlife. In 2025, there was one event due to plant failure.

13.5.3.5 SC - Loss of supply event frequency greater than 0.40 system minutes (y)

Our historical performance for the loss of supply event frequency greater than 0.40 system minutes parameter is shown in Figure 13.8.

Figure 13.8 - Loss of supply event frequency greater than 0.40 system minutes (y) 2020-2025



We met or performed better than the target for the loss of supply event frequency sub-parameter under the 'large' (y) threshold in 2020, 2021, 2024 and 2025.

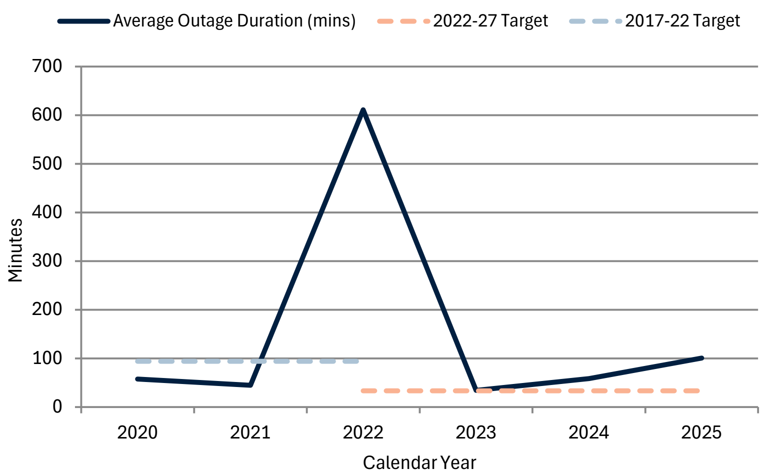
In 2022, we did not meet the target due to the de-energisation of two 110kV feeders in Brisbane to manage safety issues associated with rising flood water.

In 2023, we did not meet the target due to an event involving plant failure in the Townsville area.

13.5.3.6 SC - Average outage duration

The average outage duration parameter measures the average time to restore loss of supply events. It is calculated by the division of the total duration of loss of supply events in a year by the number of loss of supply events in that year. Our historical performance for this parameter is shown in Figure 13.9.

Figure 13.9 - Average outage duration 2020-2025



We performed better than the target for the average outage duration of loss of supply event parameter in 2020 and 2021.

In February 2022, we de-energised two 110kV feeders to our Bundamba substation for safety due to rapidly rising flood water. In 2023 and 2024, several events occurred where, on average, load restoration took slightly longer than the AER's target of 33 minutes.

In 2025, equipment failure resulted in the disconnection of a distribution network's single source of supply to rural communities resulting in an extended outage duration.

13.6 Demand Management Innovation Allowance Mechanism

The Demand Management Innovation Allowance Mechanism (DMIAM) is a funding mechanism designed to support innovation, rather than reward performance outcomes. The AER published its DMIAM for electricity transmission networks in April 2021. During the previous regulatory determination process, Powerlink empowered the RPRG to decide on the whether a DMIAM allowance should be sought in its 2023-27 Revenue Proposal. Based on the preference of the RPRG, we did not seek a DMIAM allowance for the current regulatory period.

In response to the AER's preliminary Framework and Approach paper for Powerlink's 2027-32 transmission determination, we confirmed our intent to implement innovative solutions for prescribed transmission services in the normal course of business. We also committed to investigate customer appetite for the application of the DMIAM for our 2027-32 Revenue Proposal and whether an allowance should be sought.

In its final Framework and Approach paper, the AER proposed to apply the DMIAM to Powerlink for the 2027-32 regulatory period, subject to Powerlink's customer engagement outcomes[215].

In December 2025, we provided the RPRG with information on current initiatives to identify innovative solutions for prescribed transmission services we are currently undertaking as part of business as usual and proposed an approach to not seek a DMIAM allowance as part of this Revenue Proposal.

Following engagement with the RPRG, it endorsed our proposed approach in December 2025 (refer Chapter 3 Customer Engagement). Consequently, Powerlink is not seeking a DMIAM allowance for the 2027-32 regulatory period.

[215] Framework and approach Powerlink transmission determination 2027-32, Australian Energy Regulator, July 2025, page 6.

14 Pricing Methodology

14.1 Introduction

This chapter sets out proposed amendments to our current Australian Energy Regulator (AER) approved Pricing Methodology, which will apply to Powerlink's 2027-32 regulatory period.

Our Pricing Methodology describes how we allocate our annual prescribed revenue to the various categories of prescribed transmission services and transmission network connection points, and determines the structure of our prescribed transmission service charges.

Key highlights:

- We reviewed our prescribed transmission service pricing arrangements and propose amendments to our Pricing Methodology to:
  - reflect two recent changes to the National Electricity Rules (Rules)
  - make transparent the continued implementation of the AER's decision on a pricing matter in its Final Determination on Powerlink's 2023-27 Revenue Proposal, and
  - make a minor administrative addition.
- A marked up copy of our Proposed Pricing Methodology, showing changes from our current Pricing Methodology, is included in Appendix 14.01.

14.2 Regulatory requirements

The Rules[216] require us to submit a proposed Pricing Methodology with our Revenue Proposal. The Rules also specify the requirements for a Pricing Methodology, which include consistency with the pricing principles for prescribed transmission services[217] and the AER's 2025 Pricing Methodology Guidelines[218].

14.3 Our Proposed Pricing Methodology

14.3.1 Review of pricing arrangements

Affordability remains a key issue for both our directly connected customers and distribution connected end-users, including residential and small business customers, as discussed in Chapter 2 Operating Environment.

Our customers are changing the way they use the transmission network, as transitional changes take place throughout the electricity system. To adapt to the changing environment, we are currently transitioning to locational prices based on peak demand only. This transition is being implemented over a 10-year period, across two regulatory periods, and by the end of the 2027-32 period will be fully implemented. This approach was supported by customers after an extensive engagement process and approved by the AER in its Final Determination on Powerlink's 2023-27 Revenue Proposal[219].

[216] National Electricity Rules, clause 6A.10.1.
[217] National Electricity Rules, clause 6A.23.
[218] Electricity Transmission Network Service Providers Pricing Methodology Guidelines, Australian Energy Regulator, July 2025.
[219] Final Decision Powerlink Queensland Transmission Determination 2022 to 2027, Australian Energy Regulator, April 2022, page 71.

This change provides stronger signals to our customers to encourage more efficient use of the network and enables customers to reduce their costs by changing their network usage. We will continue to implement this 10-year transition over the 2027-32 regulatory period.

14.3.2 Customer and stakeholder engagement

We engaged with a range of stakeholders as part of our review of the factors impacting prescribed transmission service prices. This engagement included Powerlink's Revenue Proposal Reference Group (RPRG) and other Transmission Network Service Providers (TNSPs).

In July 2025, we provided an overview to the RPRG of our proposed amendments to the Pricing Methodology, which included:

- changes to implement two recent Rule changes by the Australian Energy Market Commission (AEMC), and
- a minor administrative change to continue implementation of a decision approved by the AER in its Final Determination for our 2023-27 Revenue Proposal.

The RPRG supported the changes and acknowledged that the amendments were largely intended to ensure compliance with Rule changes.

We also engaged with the AER to clarify whether our Pricing Methodology should specify that the optimised replacement cost of non-prescribed designated network assets (DNAs) or identified user shared assets (IUSAs) is zero. This addition was identified through engagement with other TNSPs.

In addition, in the normal course of business we engage regularly with our directly connected customers. Powerlink reviewed issues raised by our directly connected customers in recent years and considered that no further changes to our Pricing Methodology were necessary.

14.3.3 Proposed amendments to our Pricing Methodology

The four proposed amendments to our Pricing Methodology are summarised in Table 14.1. Each of the proposed changes is permitted under the current Rules.

If necessary, we will also amend our Pricing Methodology within the regulatory period with any legislative requirements to support the delivery of the Queensland Energy Roadmap[220].

[220] Energy Roadmap 2025, Queensland Government, October 2025.

Table 14.1 - Proposed Pricing Methodology amendments

Amendment	Description
National Electricity Rule Change Implementation	
1. Provide for the recovery of non-network system security contracts	We must comply with the Improving Security Frameworks for the Energy Transition (ISF) Rule change[221]. It requires Pricing Methodology amendments to provide for TNSPs to forecast and recover their expected annual non-network system security contracts for the coming regulatory year and recover these expected contracts through prescribed transmission service prices for that year. This includes the recovery, or return to our customers, of any differences between the actual and forecast costs incurred under the contracts through prescribed transmission service prices, subject to AER approval. This Rule was first implemented in our 2025/26 prescribed transmission service prices but must now also be reflected in our Pricing Methodology.
2. Reflect the new term 'aggregate annual revenue requirement (AARR)' as the Co-ordinating Network Service Provider (CNSP)	This change reflects the AEMC's Final Rule for Providing Flexibility in the Allocation of Interconnector Costs[222] and the AER's Pricing Methodology Guidelines[223]. While we currently do not have an interconnector cost allocation agreement in place, as the CNSP for Queensland, we must update our Pricing Methodology to reflect the new terminology in the Rules.
Other Minor Administrative Changes	
3. Continue the transition to peak demand locational pricing for the remaining 5 years of the 10-year transition.	In our 2023-27 Revenue Proposal, customers supported, and the AER approved a transition to locational prices based on peak demand only. To facilitate this transition, the average demand component of the locational price is decreasing by 10 percent each year over the 2022-27 and 2027-32 regulatory periods. Our 2023-27 Pricing Methodology includes transitional arrangements for the period. Minor amendments are proposed to make transparent the continuation of the transition in the 2027-32 regulatory period.
4. Clarify that the optimised replacement cost of non-prescribed transmission system assets that are DNAs or IUSAs is zero.	This minor addition reflects the requirements of clause S6A.3.2(1) of the Rules, which was introduced by the National Electricity Amendment (Connection to dedicated connection assets) Rule 2021 no. 7. Although this is an existing requirement within the Rules (from 2021), the AER requested that we include this to improve clarity and transparency in our pricing methodology.

[221] Improving Security Frameworks for the Energy Transition, Australian Energy Market Commission, March 2024.
[222] Providing Flexibility in the Allocation of Interconnector Costs, Australian Energy Market Commission, October 2024.
[223] Electricity Transmission Network Service Providers Pricing Methodology Guidelines, Australian Energy Regulator, July 2025.

Attachment 1 Key Inputs and Assumptions

This appendix includes the key inputs and assumptions for the capital and operating expenditure forecasts and financial elements upon which our Revenue Proposal is based. Detailed information on these inputs and assumptions is included within the relevant chapters of our Revenue Proposal.

Attachment 1 Table 1 - Key Assumptions for Capital Expenditure

Element	Assumptions
General	
Asset Strategy & Information	Approved asset management documents, SAP data systems.
Estimated costs	Derived from Powerlink's standard network project estimating practices.
Demand, energy and generation forecast	Electricity demand forecast based on the central scenario outlook in Powerlink's 2025 Transmission Annual Planning Report (TAPR).
Load driven	
Augmentations, Easements & Connections	Bottom-up forecast based on network capital portfolio informed by business plans (including TAPR and adjusted Network Investment Outlook).
Contingent projects	Nine potential contingent projects: • Central to North Queensland Reinforcement • Northern Bowen Basin Reinforcement • Gladstone Area Augmentation • Central Queensland System Strength • Southern Queensland System Strength • South West Queensland Augmentation • North Brisbane Area Network Development • Brisbane Area Transfer Capacity • Surat Basin Area Network Development.
Non-load driven (reinvestment, system services security/compliance/other)	
Reinvestment	Bottom-up forecast based on network capital portfolio informed by business plans, with specific project supporting documentation subject to maturity of the project.
System Services	Bottom-up forecast based on network capital portfolio informed by business plans.
Security & Compliance/ Other	Historical trend applied, adjusted for one-off needs.
Non-network	
IT, Buildings, Vehicles	Based on current Powerlink strategies and development plans.
Tools	Historical trend applied, adjusted for one-off expenditure items.

Attachment 1 Table 2 - Key Assumptions for Operating Expenditure

Element	Assumptions
Base-trend-step	
Base year	2025/26 forecast. Independent, external report on efficiency has been commissioned.
Step changes	3 step changes included: • cloud-based services ($60 million over the period) • security uplift ($16.6 million over the period), and • network monitoring uplift ($8.8 million over the period).
Trend – output growth	0.90%, based on existing data and trended forward. Australian Energy Market Operator (AEMO) 2025 Electricity Statement of Opportunities (ESOO) Step Change Scenario. Powerlink's preliminary Annual Information Order (AIO) for 2024/25. Estimated customer data based on Ergon Energy and Energex 2025-30 Revised Revenue Proposal.
Trend – price growth	0.78%, based on forecast increases for labour (70.4% weighting) and non-labour (29.6% weighting). Labour – simple average of Wage Price Index (WPI) forecasts provided by Oxford Economics Australia (Energy, Gas, Water and Waste Services (EGWWS) – Queensland) and Deloitte Access Economics (Queensland Utilities WPI forecast). The average is 1.1% WPI. Non-labour - No real price growth based on the AER's preferred approach (0%).
Trend – productivity	0.42%, based on the AER's 2025 Draft TNSP Annual Benchmarking Report 2025 industry average benchmarking productivity.
Category specific forecasts	
AEMO participant and cyber security fees	Based on AEMO Budget and Fees FY26, with a rate of change applied to future years consistent with increases indicated in AEMO's proposed fee structure for the 2026-31 period.
Debt raising costs	8.61 basis points, based on Incenta's Benchmark debt and equity raising costs (December 2025).

Attachment 1 Table 3 - Other Inputs and Assumptions

Element	Inputs and assumptions
RoR / WACC	6.29% nominal vanilla WACC (for 2027/28).
Risk Free Rate (Rf)	*4.67% based on recent 20-day averages.*
Market Risk Premium (MRP)	*6.20% per the AER's Rate of Return Instrument.*
Equity Beta	*0.60 per AER's Rate of Return Instrument.*
Return on Equity	*8.39% calculated per AER's Rate of Return Instrument.*
Return on Debt	*4.89% (for 2027/28) based on an estimate of the AER's trailing average approach and assumes Powerlink's prevailing rate for 2025/26 remains unchanged for the 2027-32 regulatory period.*
Gamma	*0.57 per AER's Rate of Return Instrument.*
RAB	Opening RAB of $8,322.6 million ($ nominal). Forecast asset disposals of $7.7 million ($ nominal) within the 2027-32 regulatory period.
Taxation	An estimate of immediately deductible capital expenditure has been included based on historical data.
Debt raising	8.61 basis points, based on Incenta's Benchmark debt and equity raising costs (December 2025)
Inflation	2.60%, based on the AER's inflation approach and applies headline inflation from the most recent Statement on Monetary Policy from the Reserve Bank of Australia (November 2025), 5 basis points lower than the 2022-27 final determinations.
Revenue adjustments, net of tax allowance	Reduction of $285.8 million ($ nominal) arising from EBSS and CESS net carry-overs, FY22 CESS true-up and net tax allowance.

Glossary

Abbreviations	
ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
AGN	Australian Gas Networks
ATO	Australian Taxation Office
BAU	Business as usual activities
BESS	Battery Energy Storage System
BISOE	BIS Oxford Economics
CAM	Cost Allocation Methodology
CA RIN	Category Analysis Regulatory Information Notice
CCP	AER's Consumer Challenge Panel
CCP34	AER's Consumer Challenge Panel, sub-panel 34
CER	Consumer Energy Resources
CESS	Capital Expenditure Sharing Scheme
COGATI	Coordination of Generation and Transmission Investment
COTA	Council on the Ageing
CPI	Consumer Price Index
CQ-SQ	Central Queensland to Southern Queensland
CRNP	Cost Reflective Network Pricing
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAE	Deloitte Access Economics
DI	Dispatch Interval
DMIAM	Demand Management Incentive Allowance Mechanism
DNSP	Distribution Network Service Provider
DOF	Delivery Optimisation Framework
DV	Diminishing Value
EB RIN	Economic Benchmarking Regulatory Information Notice
EBSS	Efficiency Benefit Sharing Scheme
ECA	Energy Consumers Australia

Abbreviations	
EGWWS	Electricity, Gas, Water and Waste Services
EMS	Energy Management System
ENA	Energy Networks Australia
ERP	Enterprise Resource Planning
ESG	Environmental, Social and Governance
ESOO	AEMO's Electricity Statement of Opportunities
EUAA	Energy Users Association of Australia
EV	Electric Vehicle
F&A	Framework and Approach
FGOT	Future Grid Operations Technology
GDP	Gross Domestic Product
GIS	Geographical Information System
GSP	Gross State Product
GTPS	Generator Technical Performance Standards
IAP2	International Association for Public Participation
IBR	Inverter-Based Resources
ISP	Integrated System Plan
IT	Information Technology
ITAA	Income Tax Assessment Act 1997
KPI	Key Performance Indicators
kV	Kilovolt
kVA	Kilovolt-ampere
kW	Kilowatt
kWh	Kilowatt hours
MAR	Maximum Allowed Revenue
MCC	Marginal Constraint Cost
MIC	Market Impact Component
MLEC	Modified Load Export Charge
MNSP	Market Network Service Provider
MPFP	Multilateral Partial Factor Productivity
MTFP	Multilateral Total Factor Productivity
MW	Megawatts

Abbreviations	
MWh	Megawatt hours
NCC	Network Capability Component
NCIPAP	Network Capability Incentive Parameter Action Plan
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEO	National Electricity Objective
NGNO	Next Generation Network Operations
NIO	Network Investment Outlook
NSP	Network Service Provider
NSW	New South Wales
NTP	National Transmission Planner
OEFs	Operating Environment Factors
OT	Operating Technology
PFP	Partial Factor Productivity
PMUs	Phasor Monitoring Units
PPFP	Preliminary Positions and Forecasts Paper
PPI	Partial Performance Indicators
PRS	Portfolio Risk System
PTRM	Post-Tax Revenue Model
PV	Photovoltaic
QAO	Queensland Audit Office
QCA	Queensland Competition Authority
QFF	Queensland Farmers' Federation
Qld	Queensland
QNI	Queensland/New South Wales Interconnector
QRC	Queensland Resources Council
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
Repex	Replacement Expenditure
Reset RIN	AER's Reset Regulatory Information Notice
RET	Renewable Energy Target
RFM	Roll Forward Model

Abbreviations	
RIN	Regulatory Information Notice
RIT-T	Regulatory Investment Test for Transmission
RoR	Rate of Return
RPRG	Revenue Proposal Reference Group
the Rules	National Electricity Rules
SAUR	Shared Asset Unregulated Revenues
SAP	Powerlink's Enterprise Resource Planning Database
SC	Service Component
SCADA	Supervisory Control and Data Acquisition
SG	Superannuation Guarantee
SIPS	System Integrity Protection Scheme
STPIS	Service Target Performance Incentive Scheme
SVC	Static Var Compensators
TAPR	Transmission Annual Planning Report
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System
VCR	Value of Customer Reliability
WACC	Weighted Average Cost of Capital
WARL	Weighted Average Remaining Life
WPI	Wage Price Index

Appendices

The following table lists all appendices associated with Powerlink's Revenue Proposal. The author of all documents is Powerlink unless otherwise stated.

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1.03	National Electricity Rules (NER) Compliance Checklist
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4.06	Information Technology Investment Plan 2027-32
4.07	Operational Technology Investment Plan 2027-32
4.08	Future Grid Operations Technology Investment Plan 2027-32
4.09	Deliverability Assessment
4.10	2026 Network Investment Outlook
5.01	Oxford Economics - Labour Cost Escalation Forecasts to FY2032 Report
5.02	Forecast Operating Expenditure Methodology and Model
5.03	HoustonKemp - Efficiency of Powerlink's Base Year Operating Expenditure Report
5.04	Operating Expenditure Productivity Approach and Potential Initiatives
5.05	Operating Expenditure Step Changes Approach
5.06	Marsh - Insurance Forecasts 2027/28 to 2031/32
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7.01	Regulatory Asset Base Transfers
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10.01	Pricing Impact Scenarios
13.01	Setting STIPS Values
14.01	Proposed Pricing Methodology

Models

All models associated with Powerlink's Revenue Proposal are provided in the list below. Models can be accessed via the AER's website for Powerlink's revenue determination under the Proposal tab.

List of models
Capital Expenditure (Capex) Model
Capital Expenditure Sharing Scheme (CESS) Model
Capital Expenditure Trend Based Model
CESS True Up Model
Depreciation Tracking Module
Efficiency Benefit Sharing Scheme (EBSS) Model
Operating Expenditure (Opex) Model
Post-Tax Revenue Model (PTRM)
Rate of Return Model
Roll Forward Model (RFM)

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