2023-27
Powerlink Queensland
Revenue Proposal

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Executive Summary

This Revenue Proposal sets out the Queensland Electricity Transmission Corporation Limited's (Powerlink's) revenue requirements for prescribed transmission services for our next regulatory period from 1 July 2022 to 30 June 2027.

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 north of 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 build more trust with our customers, stakeholders and the AER. It is important as it sets about 80% of our annual revenue. This revenue funds the capital and operating expenditure we need to build, operate and maintain the prescribed (regulated) transmission network and is paid for by electricity customers across Queensland.

Capable of acceptance approach

Our overarching goal has been to deliver a Revenue Proposal that is capable of acceptance by our customers, the AER and Powerlink. This goal targeted acceptance of our Revenue Proposal as an overall package by relevant stakeholders at the time we lodged our Revenue Proposal with the AER in January 2021. Importantly, it has been the guiding objective for our engagement and built on the strong foundations we undertake in the normal course of business.

We have undertaken extensive engagement with our customers, stakeholders, the AER and the AER's Consumer Challenge Panel (CCP23) on all key elements of our Revenue Proposal during its development. We recognised the need to adapt our engagement approach in light of stakeholder feedback, particularly where it would provide meaningful value to our customers. As it turns out, a key milestone in our engagement was one that was not on our plan at the start. That is, the development and publication of our draft Revenue Proposal in September 2020.

While not a formal requirement of the National Electricity Rules (the Rules), we decided to prepare and publish a draft version of our Revenue Proposal for input based on the constructive engagement we had with our customers and the AER during 2020. While we have actively encouraged input and participation every step of the way, the draft Revenue Proposal provided another, perhaps more formal opportunity for feedback.

In hindsight, we consider that this was an important step (albeit unplanned and challenging to deliver at the time), which demonstrated that we were serious about our capable of acceptance goal. It also reinforced our commitment to take a 'no surprises' approach to our engagement.

Our view is that overall, our Revenue Proposal is capable of acceptance.

Our Revenue Proposal at a glance

The input we received through our engagement has directly shaped many of the positions put forward in our Revenue Proposal. In particular, our decision to propose a 3% reduction in our capital expenditure and to target no real growth in operating expenditure. These building-blocks, in addition to a significant reduction in our rate of return, has resulted in a forecast 15% decline in our Maximum Allowed Revenue (MAR).

Our prudent and efficient asset management approach has also led to a forecast decline in our Regulated Asset Base (RAB) in both nominal and real terms over the 2023-27 regulatory period[1].

We recognise that affordability remains a key concern for customers and have committed to do what we can to ensure our services are affordable and deliver value.

Under our Revenue Proposal customers can expect to see a drop of 11% in average transmission prices in the first year of the next regulatory period (2022/23), and for price growth over the remainder of the regulatory period to be in line with inflation. For average residential and small business customers, this represents an estimated saving in the first year of $13 and $23, respectively. This is on the basis of assumed tariffs and consumption[2].

1 Based on a comparison of 1 July 2022 opening RAB to 30 June 2027 closing RAB.

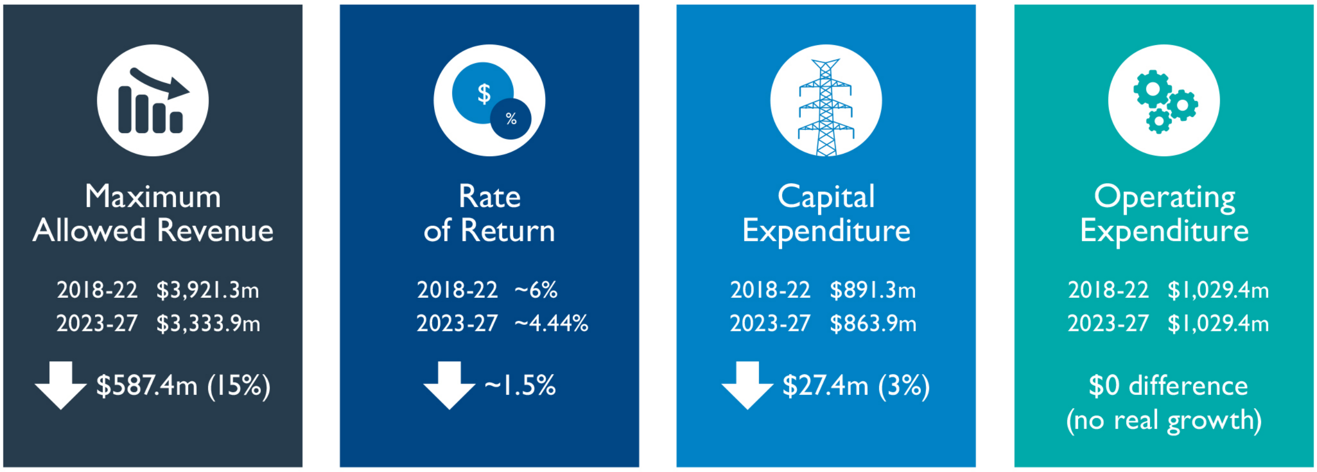
2 The transmission component of electricity bills is based on information from the Australian Energy Market Commission (AEMC) Electricity Price Trends Report, December 2020. Assumed residential consumption is based on the Queensland Competition Authority's (QCA) annual Tariff 11 (residential) median energy usage of 4,061kWh p.a. Assumed small business consumption is based on the QCA's annual Tariff 20 (small business) median energy usage of 6,831kWh p.a.

We also recognise that our impact on customer affordability is not limited to the prices we charge for transmission services. As the platform that connects electricity generators with electricity customers, we play a key role in ensuring customers have access to the lowest cost electricity when they need it. Constraints and congestion on the transmission network can lead to higher wholesale prices as more expensive generation is required to operate to meet customer demand.

Overall, our Revenue Proposal demonstrates our commitment to being customer-focused, and to continue to provide safe, secure, reliable and cost-effective transmission services to our directly-connected customers and almost five million Queenslanders.

The key elements of our Revenue Proposal are shown in Figure 1.

Figure 1: Our Revenue Proposal at a glance



Notes:
- All figures are in $m real, 2021/22 and are for the full five-year regulatory period.
- MAR is compared to the AER allowance for the 2018-22 regulatory period.
- Rate of return is nominal vanilla.
- Capital and operating expenditure are compared to the actuals/forecast for the 2018-22 regulatory period.
- Capital expenditure figures are net of disposals.
- Operating expenditure figures reflect underlying operating expenditure, which excludes movements in provisions, Network Capability Incentive Parameter Action Plan (NCIPAP) project costs, debt raising and network support costs.

Changing business and operating environment

Our Revenue Proposal has been developed during a time of significant uncertainty and change in the economic environment and in the energy sector itself. We also see a shift in our focus to take a more active role in guiding the energy market in Queensland, in this highly dynamic and uncertain energy environment.

We have identified six key business and operating environment drivers which influence our day-to-day business, as well as elements of our Revenue Proposal. These are discussed briefly below and in more detail in Chapter 2 Business and Operating Environment:

- our customers;
- COVID-19;
- the energy market;
- the economy and financial markets;
- government policy and regulation; and
- the environment.

Our customers

The cost of electricity remains a key concern for our customers. While our transmission network charges comprise around 9% of the average residential household bill, our focus does not stop there. We will continue to influence the external environment to minimise overall system costs for electricity users. In particular, we are well placed to help facilitate lower cost bulk supply electricity production, while the market transitions to a lower carbon future.

We understand that our directly-connected customers want price signals that better reflect the costs of using our network at different times and in different locations. We also know our customers are changing the way they use our network, as transformational changes take place throughout the energy market.

We engage with our directly-connected customers and a diverse range of stakeholders in the normal course of business. We have also consulted with our customers in the development of our Proposed Pricing Methodology. As a result of our Transmission Pricing Consultation we proposed to progressively transition customers to locational charges based on peak demand only. This transition will occur over the next two regulatory periods (or 10 years). This is discussed further in Chapter 16 Pricing Methodology.

COVID-19

Additional challenges have been presented by the COVID-19 pandemic, not only for Powerlink but for our customers and stakeholders. It is impossible to predict the likely path and duration of the pandemic.

Our first and foremost commitment during the pandemic is the protection of the health, safety and wellbeing of our people, contractors and the communities in which we operate. The adversity of responding to COVID-19 has also provided further impetus for us to develop and implement new ways to manage our business and respond to challenges, as well as opportunities for innovation.

The energy market

As the National Electricity Market (NEM) continues to transition toward a new energy future, we must navigate a highly dynamic and uncertain environment. The transmission system has changed from one which transports electricity from a small number of large centralised generators to major loads and distributors, to one that interconnects increasing numbers of generators, loads and storage and transports energy to where it is needed. The rapidly changing energy system is also a key issue of concern for our customers and stakeholders.

Between 2018 and 2020, we developed our 30 year Network Vision with input from customers, stakeholders and energy industry experts. We have further developed the broad themes of our Network Vision – changing electricity consumption patterns, a lower carbon future and decentralised energy sources – into the 'four D's'. These are discussed in detail in Chapter 2 Business and Operating Environment and include:

- ***Decarbonisation*** – the growth of large-scale renewable generation capacity on the transmission network presents technical challenges in keeping electricity supply and demand in balance and creates complexity in how we plan and operate the network. In particular, system strength has emerged as a prominent challenge in Queensland.
- ***Decentralisation*** – rapid installation of renewables and the forecast closure of ageing coal generation assets across the NEM have driven large changes in power flows across the network. This introduces a high degree of uncertainty around the need for investment in major transmission network flow paths.
- ***Demand disruption*** – Queensland is experiencing changes to its demand and energy patterns. Solar uptake at a household level is driving higher and shorter demand peaks and demand during the day has reduced to levels that impact on the technical capability of daytime baseload generation to operate. These opposing factors mean it is increasingly difficult to determine the optimal investment strategy for some assets, or whether they could potentially be decommissioned.
- ***Digitisation*** – the transformation of data into information, and then insights, can improve business decision-making and reduce risks to our customers. We are seeking ways to deploy and access enhanced digital data analytics to support the business and provide better services to our customers.

It is clear that as we transition to a new energy future, investment will need to take a 'whole of system' perspective. This will require greater coordination of investment strategies between generation, transmission and distribution businesses to deliver appropriate outcomes for customers. We are working with customers, regulators, project proponents, suppliers and the Australian Energy Market Operator (AEMO) to identify, understand and appropriately prepare for and respond to these challenges.

The economy and financial markets

The COVID-19 pandemic is currently the dominant influence on the economy and financial markets and remains the main source of uncertainty for the economic growth outlook.

The Reserve Bank of Australia (RBA) describes the COVID-19 pandemic as the largest shock to the global economy in many decades[3]. There remains considerable economic uncertainty domestically and globally. This outlook has had a direct impact on the demand for electricity in the short-term, and may continue into the medium and long-term. It has also impacted key assumptions that underpin our Revenue Proposal such as inflation, labour cost escalators and elements of our rate of return.

[3] Statement on Monetary Policy August 2020, Reserve Bank of Australia, page 1.

We also expect there to be risks in terms of access to skilled resources and delivery over our next regulatory period. Australia has a limited pool of skilled labour for large electricity infrastructure investments, and there is a potentially significant period of transmission work to occur across the NEM. Competition for scarce resources may influence the cost of our projects, in particular capital projects, and we will need to manage this impact if it arises.

Government policy and regulation

There are a number of key regulatory consultations underway that could significantly impact the provision of electricity transmission services. This includes the Coordination of Generation and Transmission Investment reforms, the Energy Security Board Post 2025 Market Design, Transmission Ring-Fencing Review and the Energy Security Board's consultation on planning rules for Renewable Energy Zones (REZs). The outcome of these regulatory reforms could have material impacts on our operations, such as changes to funding models for future network investment and the way revenue is collected.

Federal and Queensland Government policies establish broad frameworks that can have important implications for market participants and we have had regard to these policies in the development of our Revenue Proposal. This includes the Queensland Government's 50% Renewable Energy Target, the progressive increase to the Superannuation Guarantee rate and the recent introduction of the *Security Legislation Amendment (Critical Infrastructure) Bill 2020*, which would establish a new security and resilience regulatory regime on operators of critical infrastructure.

We are also working with the Queensland Government to understand and progress key initiatives related to the potential delivery of transmission infrastructure to support renewable energy developments.

The environment

Extreme weather such as cyclones, bushfires and floods can have a significant impact on the transmission network. The increased prevalence and intensity of these events in recent years also creates broader challenges for the ongoing design, maintenance and operation of the network.

Our network has not been materially impacted by recent bushfires or other severe weather events and we have not forecast any capital expenditure to address weather-related risks over the forthcoming regulatory period. However, we are experiencing upward pressure on insurance premiums due to the impact of extreme weather events elsewhere in the domestic and international markets, which has impacted, and is forecast to continue to impact, our operating expenditure.

That said, we have consulted with our customers and the AER on our insurance and will continue to engage directly with insurance underwriters to ensure appropriate arrangements are put in place to manage these risks.

Delivering on our commitments

During the 2018-22 regulatory period, we have delivered on our commitment to provide better value to our customers through increased efficiency and cost reduction while continuing to provide a safe, secure and reliable transmission network.

We are responding to customer affordability concerns through the forecast delivery of a 35% decrease in capital expenditure and a 7% decrease in operating expenditure compared to the 2013-17 regulatory period. As a result, in this regulatory period our RAB has decreased in both real and nominal terms[4].

Our performance in this regulatory period is outlined briefly in the following sections and discussed in detail in Chapter 4 Historical Capital and Operating Expenditure.

Capital expenditure

Our total actual/forecast capital expenditure over the 2018-22 regulatory period relative to the AER's allowance is shown in Table 1.

Table 1: Capital expenditure – allowance vs actual/forecast ($m real, 2021/22)[(1)]

	2017/18	2018/19	2019/20	2020/21 (forecast)	2021/22 (forecast)	Total
Allowance	175.7	176.3	179.6	186.8	174.7	**893.1**
Actual/forecast	158.7	175.0	172.6	178.6	206.4	**891.3**

(1) This table is net of disposals.

4 Based on a comparison of 1 July 2017 opening RAB to 30 June 2022 closing RAB.

Total capital expenditure is forecast to be $1.8m (0.2% lower) than the AER's total capital expenditure allowance for the 2018-22 regulatory period. This is primarily due to some delays in the delivery of our capital works due to COVID-19 and lower non load-driven capital expenditure due to low demand growth and the emergence of system strength issues. This underspend has been offset, at least in part, by additional capital expenditure on ground clearance rectification works.

Operating expenditure

Our total actual/forecast operating expenditure over the 2018-22 regulatory period relative to the AER's allowance is shown in Table 2.

Table 2: Operating expenditure – allowance vs actual/forecast ($m real, 2021/22) (1)

	2017/18	2018/19	2019/20	2020/21 (forecast)	2021/22 (forecast)	Total
Allowance	206.8	205.9	205.0	204.3	204.2	**1,026.1**
Actual/forecast	198.1	206.6	208.3	212.9	209.6	**1,035.6**

(1) Figures are exclusive of debt raising costs

We expect total operating expenditure to be $9.5m (0.9%) higher than the AER's total allowance for the 2018-22 regulatory period. This is primarily due to higher costs incurred in relation to the Australian Energy Market Commission (AEMC) Levy. The AEMC Levy is a cost recovered from Powerlink by the Queensland Government and is outside our control.

Regulatory Asset Base

Our prudent and efficient asset management approach has led to a forecast decline in our RAB of $111.0m in nominal terms and $621.9m in real terms over the 2018-22 regulatory period[5]. The decline in our RAB also aligns with our flat or declining forecasts of delivered energy. From a reinvestment perspective, this trend demonstrates that where reinvestment is required to address a network need we consider a range of options and do not necessarily replace like-for-like.

Benchmarking performance

We have had regard to our performance relative to other electricity Transmission Network Service Providers (TNSPs) in the development of our Revenue Proposal. We engaged HoustonKemp to provide an independent review of our relative performance, based on the AER's 2020 Benchmarking Report. HoustonKemp found that Powerlink, both in absolute and trend terms, is operating relatively efficiently when compared to our peers.

We have improved our operating expenditure productivity performance in the current regulatory period, primarily as a result of our operating expenditure reduction of approximately 7% between the 2013-17 and 2018-22 regulatory periods. Overall, our operating expenditure performance across major expenditure categories has been improving and is consistent with the key characteristics of our network relative to other stand-alone TNSPs.

We recognise we can continue to improve on our operating expenditure performance, which is why we have set a target of no real growth in operating expenditure between the current and next regulatory periods. This target is underpinned by a proposed real productivity growth of 0.5% per annum, which is higher than the current industry average of 0.3%, and no step changes.

Network performance

Our overall performance under the Service Component (SC) and Network Capability Component (NCC) elements of the Service Target Performance Incentive Scheme (STPIS) for the 2018-22 period has been strong.

However, our performance under the Market Impact Component (MIC) component of the scheme has been impacted by changes in power flows and the emergence of system strength constraints, which is expected to continue into the 2023-27 regulatory period. We will continue to respond to these challenges to ensure that the needs of our customers are met and that we continue to meet our network security and reliability obligations.

We remain firmly of the view that the STPIS should be reviewed in light of the significant and rapid changes in the energy market to ensure it remains fit-for-purpose and continues to promote the long-term interests of consumers.

5 Based on a comparison of 1 July 2017 opening RAB to 30 June 2022 closing RAB.

Delivering further value

The business and operating environment for Powerlink, and for many of our customers, is one of change and uncertainty. Affordability, the impact of COVID-19 on the economy and the challenges presented by an energy system in transition are all key factors that have shaped our Revenue Proposal.

Our Revenue Proposal demonstrates our commitment to being customer-focused, and to continuing to provide safe, secure, reliable and cost-effective transmission services to our directly-connected customers and almost five million Queenslanders.

The following section provides a brief overview of the key elements of our Revenue Proposal – forecast capital expenditure, forecast operating expenditure, RAB and rate of return.

Forecast capital expenditure

We received consistent feedback on our draft Revenue Proposal which highlighted that a 12% increase in capital expenditure, compared to the current regulatory period, was a serious concern for our customers. We have an ongoing focus on how we can more prudently and efficiently manage the transmission network while continuing to deliver safe, secure and reliable electricity transmission services for our customers. This means we continue to challenge ourselves on the need for proposed investments, and is now reflected in a proposed reduction in capital expenditure, compared to the current regulatory period.

A summary of our forecast capital expenditure for the 2023-27 regulatory period is presented in Table 3.

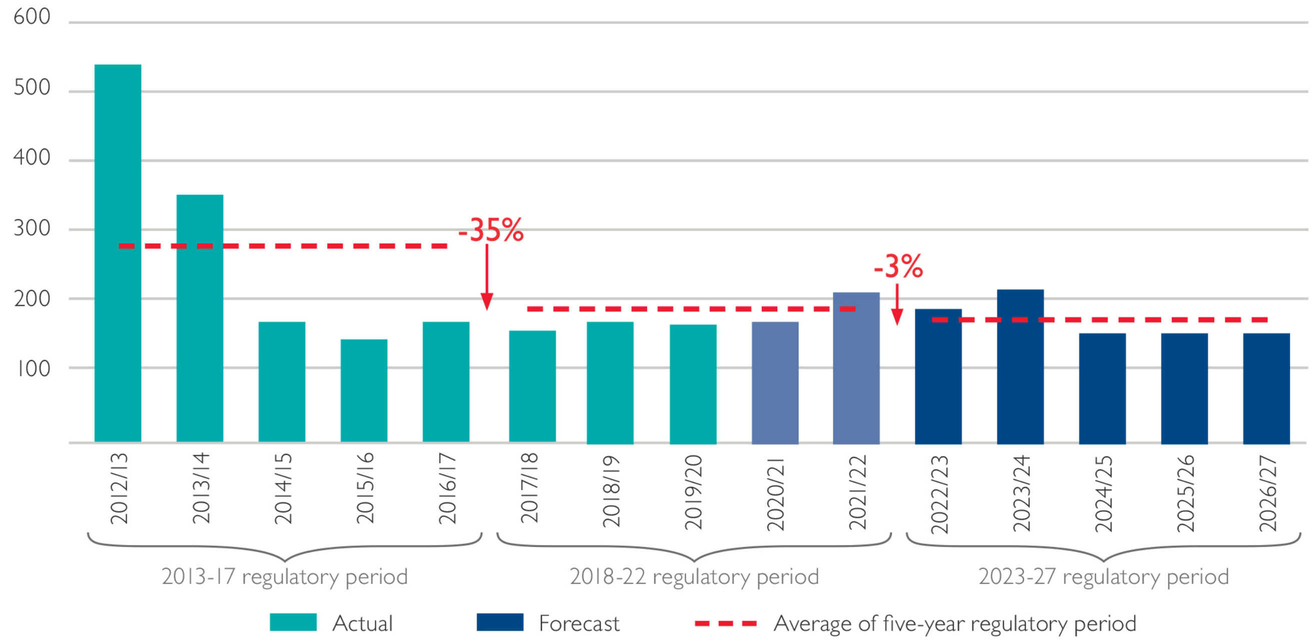
Table 3: Forecast capital expenditure ($m real, 2021/22)(1)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Total capital expenditure	190.9	209.4	157.2	152.4	154.0	**863.9**

(1) This table is net of disposals.

Figure 2 shows our total annual capital expenditure profile since 2012/13, including our forecast for the next regulatory period.

Figure 2: Actual and forecast total capital expenditure ($m real, 2021/22)



Our total forecast capital expenditure for the 2023-27 regulatory period is $863.9m, which is $27.4m (3.1%) lower than actual/forecast expenditure for the 2018-22 regulatory period. The majority of this ($726.1m or 84%) is non load-driven network expenditure.

The primary driver of our capital expenditure over the 2023-27 regulatory period is targeted reinvestment in the transmission network to maintain security, reliability and quality of supply as our assets continue to age. Our low demand growth environment means only $2.4m of our capital expenditure forecast is driven by increased maximum demand.

As a result of the decline in minimum demand, we anticipate a need for further investment in additional reactive power control devices to maintain power system voltages within secure limits. Our forecast also includes $22.5m for these devices to support prescribed transmission services.

To forecast our capital expenditure in the 2023-27 regulatory period we have built on the experience, input and feedback gained during our previous revenue determination process and have again applied a hybrid approach. This approach integrates top-down and bottom-up methods and includes the provision of project-specific supporting justification for over 70% of our total forecast capital expenditure, complemented by the top-down forecast for remaining assets.

Further detail is provided in Chapter 5 Forecast Capital Expenditure.

Forecast operating expenditure

We have heard customer feedback on business productivity, affordability and the impacts of the current economic climate. Based on this feedback and our goal to have a Revenue Proposal that is capable of acceptance by our customers, the AER and Powerlink at the time we lodge our Revenue Proposal, we have committed to pursue a target of no real growth in operating expenditure compared to our actual/forecast operating expenditure over the current regulatory period[6].

A summary of our forecast operating expenditure for the 2023-27 regulatory period is presented in Table 4.

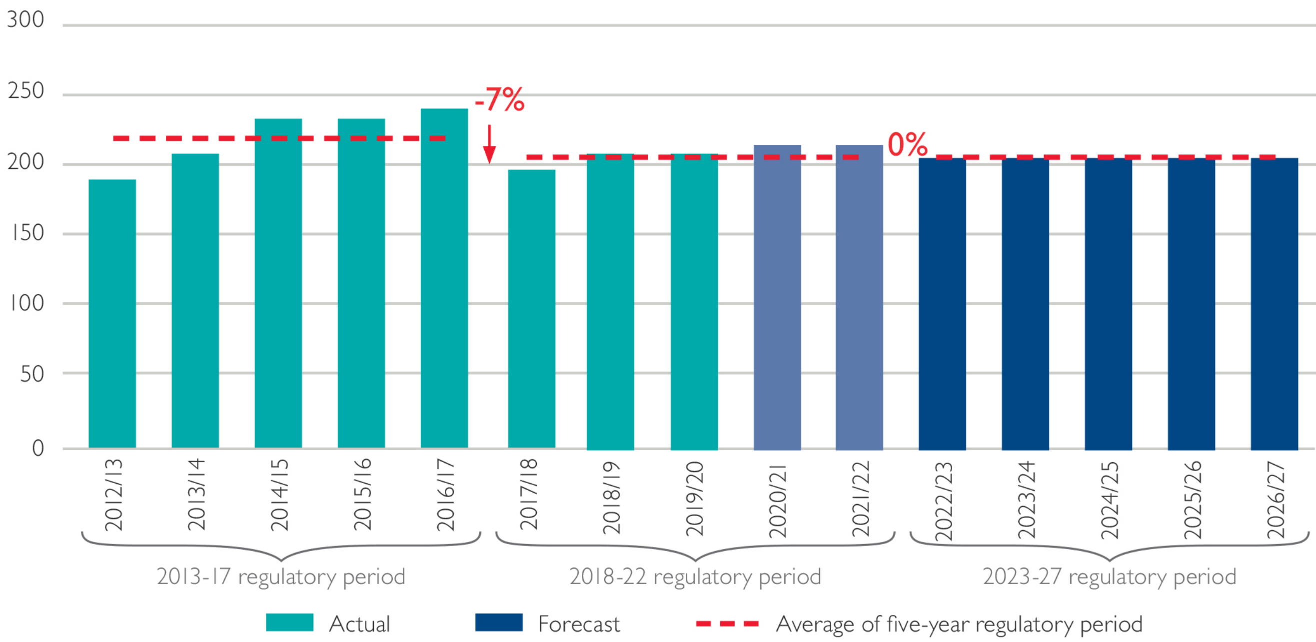
Table 4: Forecast operating expenditure ($m real, 2021/22)[(1)]

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Total operating expenditure	203.9	206.3	205.8	206.5	206.9	**1,029.4**

(1) This table excludes debt raising costs. Our operating expenditure forecast is $1,046.4m with debt raising costs included.

Figure 3 shows our underlying total annual operating expenditure profile since 2012/13, including the forecast for the 2023-27 regulatory period.

Figure 3: Actual and forecast total operating expenditure ($m real, 2021/22)[(1)]



(1) Reflects underlying operating expenditure, excluding movements in provisions, debt raising, network support and NCIPAP costs.

Our total forecast operating expenditure of $1,029.4m represents $0 (no real growth) from underlying actual/forecast operating expenditure for the 2018-22 regulatory period.

6 For clarification, underlying operating expenditure excludes movements in provisions, Network Capability Incentive Parameter Action Plan (NCIPAP) project costs which are part of the STPIS, debt raising costs and network support costs. This is explained further in Chapter 6 Forecast Operating Expenditure.

To achieve this target we have proposed, in combination, a higher than industry average productivity factor of 0.5% per annum and have not pursued any step changes.

The adoption of this approach represented a significant shift for our business during the development of our Revenue Proposal and it will be a challenge for us to meet this stretch target. However, on balance, we considered that we should rise to this challenge in the interests of customers and to drive our business hard to find further efficiencies and productivity improvements to become a world-class transmission service provider.

We have included a range of potential productivity initiatives in Chapter 6 Forecast Operating Expenditure that could be implemented to achieve this.

Regulatory Asset Base

We will continue to apply our prudent and efficient asset management approach in the next regulatory period and forecast our RAB to continue to decline by $19.4m in nominal terms and $749.6m in real terms[7].

We have also proposed to transfer in net terms, $2.4m of prescribed assets out of our RAB at 30 June 2022. This is outlined further in Chapter 8 Regulatory Asset Base.

Rate of return

We have applied the Australian Energy Regulator's (AER) binding 2018 Rate of Return Instrument to calculate the rate of return for our Revenue Proposal. This results in an estimated post-tax nominal rate of return of 4.44% in the first year of the 2023-27 regulatory period (2022/23), which is a substantial reduction from our current rate of return of approximately 6%. The main driver of our lower rate of return is the historically low risk free (Government bond) rate environment.

Revenue requirement and price path

We have estimated our total building-block revenue requirement using the AER's Post-Tax Revenue Model (PTRM). The smoothed revenue requirement and resulting X-factors is summarised in Table 5.

Table 5: X-factors and smoothed MAR ($m nominal)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Unsmoothed revenue requirement	700.2	693.4	711.3	724.5	735.0	**3,564.4**
X-factors	12.59%	0.57%	0.57%	0.57%	0.57%	
Smoothed MAR	**689.7**	**701.1**	**712.8**	**724.7**	**736.8**	**3,565.1**

In real terms, our smoothed revenue for 2022/23 is forecast to reduce by 12.59% compared to our forecast revenue in the 2021/22 year. In subsequent years of the regulatory period our annual revenue is forecast to reduce by 0.57% per annum in real terms.

Overall, the total MAR for the 2023-27 regulatory period is forecast to be 15% less than our allowed MAR for the current regulatory period.

Price path

Our contribution to the average Queensland electricity bill is currently 9% for households and small businesses[8]. This equates to approximately $118.5 per annum for residential customers[9] and approximately $200.7 for small businesses[10].

Based on our forecast revenue, the indicative impact on the transmission component of electricity prices in the first year of the next regulatory period (2022/23) would be:

- Residential: a nominal reduction of approximately $13 (11%), real reduction of $16 (13%).
- Small Business: a nominal reduction of approximately $23 (11%), real reduction of $26 (13%).

On average, price increases for residential customers and small businesses will remain in line with inflation (assumed forecast of 2.25%) for the remainder of the 2023-27 regulatory period.

7 Based on a comparison of 1 July 2022 opening RAB to 30 June 2027 closing RAB.
8 Residential Electricity Price Trends Report 2020, Australian Energy Market Commission, December 2020.
9 Based on the Queensland Competition Authority's (QCA) annual Tariff 11 (residential) median energy usage of 4,061kWh per annum, March 2020.
10 Based on the QCA's annual Tariff 20 (small business) median energy usage of 6,831kWh per annum, March 2020.

The estimated impact of our forecast MAR on the transmission component of average annual electricity bills in each year of the 2023-27 regulatory period is outlined in Table 6. The final year of the current regulatory period is included to show the change in the first year of the next regulatory period.

Table 6: Indicative electricity price impacts ($ nominal)

	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Residential annual bill	118.5	105.2	106.4	109.0	111.9	115.0
Annual change	**-**	**(13.3)**	**1.2**	**2.6**	**2.9**	**3.1**
Small business annual bill	200.7	178.2	180.3	184.7	189.6	194.8
Annual change	**-**	**(22.5)**	**2.1**	**4.4**	**4.9**	**5.2**

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1. Introduction

This Revenue Proposal presents the Queensland Electricity Transmission Corporation Limited's (Powerlink's) proposed revenue requirements for prescribed transmission services for our next regulatory period from 1 July 2022 to 30 June 2027.

We have developed our Revenue Proposal consistent with Chapter 6A of the National Electricity Rules (the Rules), the Australian Energy Regulator's (AER's) Framework and Approach Paper[1] and the Final Regulatory Information Notice (RIN) issued to Powerlink by the AER dated 14 October 2020 for the purpose of this Revenue Proposal (the Reset RIN).

Our Revenue Proposal reflects the outcomes of extensive engagement with our customers and stakeholders, including our Customer Panel and a sub-group of that panel, the Revenue Proposal Reference Group (RPRG), the AER and the AER's Consumer Panel for our Revenue Proposal (CCP23). We acknowledge the time and resources committed by our customers and stakeholders 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 for electricity customers;
- the Revenue Proposal (this document);
- appendices and supporting information for the Revenue Proposal;
- 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 north of Cairns to the New South Wales (NSW) border.

Our role in the electricity supply chain is to transport high voltage electricity generated at power stations, through the transmission grid to the distribution networks owned by Energex and Ergon Energy (part of the Energy Queensland Group) and Essential Energy (in northern NSW) to ensure a safe, secure, reliable and cost-effective power supply to almost 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/New South Wales Interconnector (QNI) transmission line.

We are registered with the Australian Energy Market Operator (AEMO) as a Transmission Network Service Provider (TNSP) and we hold a Transmission Authority issued under the *Electricity Act 1994*. We have also been appointed by the Queensland Government as the entity responsible for transmission network planning in Queensland (the Jurisdictional Planning Body) for the purposes of the Rules[2].

1.2 Our services

We provide prescribed transmission services consistent with the Rules, the *Electricity Act 1994* and our Transmission Authority. These services include:

- shared transmission services provided to directly-connected customers and distribution networks (prescribed Transmission Use of System (TUOS) services);
- connection services for the Queensland Distribution Network Service Providers (DNSP) 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).

[1] Final Framework and Approach Paper for Powerlink, Australian Energy Regulator, July 2020.
[2] National Electricity Rules, Chapter 10.

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 this document

This Revenue Proposal document provides an overview of our business and operating environment, customer engagement process, expenditure forecasts and proposed revenue requirements for the 2023-27 regulatory period.

Table 1.1: Structure of this document

Chapter	Content
1	Introduction.
2	Business and operating environment and an overview of the opportunities and challenges we face now and into the 2023-27 regulatory period.
3	Customer engagement approach and how customer input has contributed to the development of our Revenue Proposal.
4	Historical capital and operating expenditure.
5	Capital expenditure forecast for the 2023-27 regulatory period.
6	Operating and maintenance expenditure forecast for the 2023-27 regulatory period.
7	Cost escalation rates and project cost estimation approach.
8	Calculation of our Regulatory Asset Base (RAB).
9	Rate of return, taxation allowance and inflation forecast.
10	Depreciation forecast.
11	Maximum Allowed Revenue (MAR), based on our building-block forecasts and revenue adjustments.
12	Proposed pass through arrangements.
13	Assessment of shared assets.
14	Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS) forecasts and 2018-22 regulatory period carryovers.
15	Service Target Performance Incentive Scheme (STPIS) 2018-22 regulatory period performance and 2023-27 regulatory period targets.
16	Proposed Pricing Methodology.
17	Approach to the Demand Management Innovation Allowance Mechanism (DMIAM).

1.4 Conventions

In our Revenue Proposal we have applied the following number conventions, unless otherwise specified:

- negative figures are presented in brackets;
- historical and forecast expenditure is presented in end-year (to 30 June) real 2021/22 dollars; and
- our revenue building-blocks from the Post-Tax Revenue Model (PTRM) are presented in end-year (to 30 June) nominal dollars.

Totals presented in tables may not add 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.

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[3].

[3] Better Regulation: Confidentiality Guideline, Australian Energy Regulator, November 2013.

1.6 Governance and compliance

Our Board has issued a resolution in relation to this Revenue Proposal to certify that the key assumptions that underlie the capital and operating expenditure forecasts are reasonable[4] (refer to Appendix 1.01).

We also provide a Statutory Declaration from our Chief Executive in relation to the historical and forecast data contained in our Reset RIN (refer to 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 1.6 of the Reset RIN, in Appendix 1.05 Document Register.

[4] National Electricity Rules, schedule S6A.1, clause S6A.1.1(5), S6A.1.2(6).

2. Business and Operating Environment

2.1 Introduction

This chapter sets out the key external drivers that currently impact Powerlink, or are expected to impact Powerlink, over the 2023-27 regulatory period and beyond.

This chapter builds on our Business Narrative which we developed early in our customer engagement process for our Revenue Proposal (refer Chapter 3 Customer Engagement and Appendix 2.01 Business Narrative).

Key highlights

- Affordability remains a key concern for customers. We recognise customers expect us to do what we can to ensure affordable services and value for money.
- There are significant changes occurring in energy markets as we transition to a low-carbon future. Decarbonisation, decentralisation, demand disruption, and digitisation necessitate changes to our patterns of operation.
- We are in an uncertain economic environment, driven primarily by COVID-19, which has placed pressure on our business and also on our customers and stakeholders.
- The level of uncertainty that exists means it is more difficult to forecast into the 2023-27 regulatory period.
- We have prepared our Revenue Proposal with regard to the business and operating environment factors in this chapter and have proposed expenditure forecasts and revenue requirements that reasonably reflect the efficient costs of a prudent operator and a realistic expectation of demand and cost inputs.
- We consider our forecasts are capable of acceptance by our customers, the Australian Energy Regulator (AER) and ourselves.

2.2 Our approach

Our business and operating environment continues to present challenges and opportunities for Powerlink. Our priority remains to deliver safe, secure, reliable and cost-effective electricity transmission services to our customers. We also see a shift in our focus to take a more active role in guiding the energy market in Queensland, during what is a highly dynamic and uncertain energy environment.

We have identified six key business and operating environment drivers. These drivers influence our day-to-day business, as well as elements of our Revenue Proposal, and are discussed in further detail in the following sections. They are:

- our customers;
- COVID-19;
- the energy market;
- the economy and financial markets;
- government policy and regulation; and
- the environment.

2.3 Customer drivers

We are a foundation signatory to The Energy Charter and are committed to customer-focused responses to the challenges and opportunities that lie ahead. We are committed to being a customer-centric business and recognise this is an ongoing journey for the business. Our aim is to embed our customers' needs, views and priorities in our day-to-day business activities, and in key decision-making such as the development of our Revenue Proposal.

The following sections outline the three key customer drivers that have influenced our Revenue Proposal: affordability, price signals and customer choice. More detail on our engagement approach and response to customer feedback on our Revenue Proposal is included in Chapter 3 Customer Engagement.

2.3.1 Affordability

The cost of electricity remains a key concern for customers. While our transmission network charges comprise around 9% of the average residential household bill (refer Figure 2.1), our focus does not stop here. We will continue to influence the external environment to minimise overall system costs for electricity users. In particular, we are well placed to help facilitate lower cost bulk supply electricity production, while the market transitions to a lower carbon future.

Figure 2.1: Breakdown of typical Queensland household electricity bill

9%

The cost of Powerlink's high voltage electricity grid represents around 9%* of the total delivered cost of electricity for the typical Queensland residential electricity customer.

Electricity supply chain components	Proportion of electricity bill
Generation	29%
Transmission	9%
Distribution	40%
Retail and other^	10%
Environmental policies	12%

*2020 Residential Electricity Price Trends Report – SEQLD supply chain components 2021/22.
^Includes costs associated with retail, metering, losses and errors in the estimated value of all other supply chain cost components. The AEMC 2020 Residential Price Trends Report refers to this overall component as residual.

Customers expect us to do what we can to ensure affordable services and value for money. Over the current 2018-22 regulatory period we are responding to customer affordability concerns, through the forecast delivery of a 35% decrease in capital expenditure and a 7% decrease in operating expenditure compared to the 2013-17 regulatory period.

During the current regulatory period, our Regulatory Asset Base (RAB) has declined in real and nominal terms. In the 2023-27 regulatory period we expect this trend to continue as a result of our forecast 3% decrease in capital expenditure. This demonstrates the prudency of our approach to asset management, which is discussed further in Chapter 5 Forecast Capital Expenditure.

We have also proposed a target of no real growth in operating expenditure for the 2023-27 regulatory period. This will be a challenge for our business to meet, but is the right approach in the context of affordability and the current and mid-term economic climate, and was directly influenced by feedback from our customers on affordability concerns. We discuss this further in Chapter 6 Forecast Operating Expenditure.

We recognise our impact on customer affordability is not limited to the prices we charge for transmission services. As the platform that connects electricity generators with electricity customers, we play a key role in ensuring customers have access to the lowest cost electricity, when they need it. Constraints and congestion on the transmission network can lead to higher wholesale prices as more expensive generation is required to operate to meet customer demand.

As part of the economic assessment for major new transmission network investments, we analyse these potential benefits of improved operation of the wholesale market. In this way we seek an appropriate overall outcome for everyone who produces, transports and consumes electricity. We also support the goal of co-optimisation of generation and transmission development in the long-term interests of customers.

We also have regard to Australian Energy Market Operator's (AEMO's) Integrated System Plan (ISP), which presents an integrated approach to the development of renewable energy resources in the National Electricity Market (NEM) and a roadmap for Australia's eastern power system for the next 20 years. While the aim of the ISP is to set out a long-term optimal development path for the NEM, its success depends on the market's confidence in that plan. In particular, this requires demonstration of a development process that is robust, transparent and enabled by effective stakeholder engagement. As customers are expected to pay for significant system investments over the next 20 years, it is important to have transparency around the robustness of AEMO's analysis, the efficiency of costs and the impact on customers.

It is not in the best interests of our customers for electricity prices to reflect allowances that include costs for projects or initiatives whose scope, timing and/or cost remains uncertain. For this reason, we pursued the concept of contingent reinvestment projects in the development of our Revenue Proposal. The reason we pursued this was to ensure the cost of these uncertain but probable projects was not borne by customers within the ex-ante capital expenditure allowance and hence the revenues determined by the AER up-front.

Feedback from customers, the AER and the AER's Consumer Challenge Panel (CCP23) on the concept of contingent reinvestments primarily related to a concern that the triggers associated with contingent reinvestment may not be 'objectively verifiable'[1], which is a key requirement for contingent projects, and that further engagement on this point between Powerlink, customers and the AER is needed. Based on this feedback, we ultimately decided not to include any contingent reinvestment projects in our Revenue Proposal. However, we consider that the concept of contingent reinvestment projects remains appropriate and will seek to pursue this concept outside our Revenue Proposal process.

The commitment we have made to The Energy Charter is to make ourselves accountable to our customers across all aspects of our operations, which includes improved energy affordability. Consistent with that commitment, we have worked to ensure that our forecast expenditure for the 2023-27 regulatory period is prudent, efficient and essential to the delivery of safe, secure and reliable electricity supply.

2.3.2 Price signals

We understand that our directly-connected customers want price signals that better reflect the costs of using our network at different times and in different locations. Such changes could also potentially benefit all customers over the long-term, as more cost reflective price signals incentivise more efficient use of the network. This in turn can ease pressure on the network in periods of high demand, and therefore reduce future network costs.

We also know our customers are changing the way they use our network, as transformational changes take place throughout the energy system. To help identify where we could improve our transmission pricing arrangements, we have undertaken consultation on these issues to inform our Proposed Pricing Methodology.

As a result of this consultation, we have proposed one key amendment to our existing Pricing Methodology. This amendment will progressively transition customers locational charges to be based on peak demand only. This transition will occur over the next two regulatory periods (or 10 years), commencing 1 July 2022.

Chapter 16 Pricing Methodology discusses our consultation and Proposed Pricing Methodology changes in further detail.

2.3.3 Customer choice

Customers want a greater say in how they access, use and pay for electricity as our energy system transitions. Consistent with trends across all aspects of our daily lives, a 'one size fits all' model is not appropriate. Technologies such as Distributed Energy Resources (DER), battery storage and smart home automation systems have the potential to fundamentally transform the way households and communities manage their energy needs. This necessitates flexibility and adaptability in responding to these different needs, which could also change through time.

Delivery of a more flexible network has implications for our business. For example, the operation of our network is more complex due to added power system security constraints. We are exploring innovative technology applications to improve the flexibility of our operating practices in response to market changes, such as the use of Phasor Monitoring Units (PMUs) to improve our ability to monitor and respond to the changing characteristics of the power system as more Inverter-Based Resources (IBR) connect to the network.

The implications of the changing energy market for our business is explored further in Section 2.5.

2.4 COVID-19

Additional challenges have been presented by the COVID-19 pandemic, not only for Powerlink but for our customers and stakeholders. It is impossible to predict the likely path and duration of the pandemic.

Our first and foremost commitment during the pandemic is the protection of the health, safety and wellbeing of our people, contractors and the communities in which we operate. The adversity of responding to COVID-19 has also provided further impetus for us to develop and implement new ways to manage our business and respond to challenges, as well as opportunities for innovation.

We have summarised the impacts of the pandemic on our business that have occurred, and/or could impact us in the 2023-27 regulatory period, in Table 2.1.

[1] National Electricity Rules, clause 6A.8.1(c).

Table 2.1: COVID-19 impacts

Area	Impact
Affordability	We recognise that COVID-19 has had and may continue to have a very significant impact on the livelihoods and economic security of our customers. Affordability of supply for our customers during these uncertain economic times is a key goal of ours. For the remainder of the current regulatory period, this means that we must manage our capital and operating expenditure within the AER's allowance. For the 2023-27 regulatory period, we have proposed no real growth in our operating expenditure and a 3% reduction in our capital expenditure compared to actuals/forecast in the current regulatory period as two key measures to respond to customer concerns about affordability.
Engagement	We have adjusted our engagement approach (e.g. greater use of digital technology) to be able to effectively conduct our consultation remotely. This has occurred for our business-as-usual engagement, and for engagement on our Revenue Proposal. We think this approach has been successful, all things considered. We will look to integrate greater digital engagement, along with more traditional face-to-face engagement, post-COVID to enable wider engagement from customers and stakeholders across Queensland.
Economic impacts	COVID-19 has had significant and pervasive impacts on both the domestic and global economies. These impacts affect our customers, suppliers and the broader communities in which we operate. Australia has fared comparatively well and recent economic data has been better than previously expected(1). However, the economic recovery path remains uncertain and impacts include: • Economic activity: Queensland experienced a 5.9% fall in domestic economic activity in the June quarter of 2020. However, the State budget notes that Queensland has fared better than other states. It forecast flat Gross State Product (GSP) to 2020/21, which is expected to rebound in 2021/22. It also forecast average unemployment of 7.5% in 2020/21 will improve steadily over the coming years, falling to 6.5% by 2022/23(2). • Inflation: we have observed a volatile and low/negative inflation environment in 2019/20 and so far in 2020/21. Inflation is a key input across a number of elements of our Revenue Proposal and persistently low, volatile or negative periods of inflation mean this is a difficult input to accurately forecast in the current environment (refer Chapter 9 Rate of Return, Taxation and Inflation). • Interest rates: COVID-19 has impacted Government bond yields (i.e. the risk-free rate), as well as the debt risk premium. This has contributed to a significant reduction in our rate of return between the current and next regulatory periods, which impacts on our overall financial sustainability (refer Chapter 9 Rate of Return, Taxation and Inflation). • Wages growth: we anticipate COVID-19 to have an impact on wage growth and the Wage Price Index (WPI), which is a key trend factor for operating expenditure. This is discussed further in Chapter 7 Escalation Rates and Project Cost Estimation.
Demand and energy	AEMO has observed short-term reductions in both peak demand and energy consumption as living and working habits changed across Australia. These factors cast a degree of uncertainty on electricity demand forecasts in the short-term, acknowledged by the AEMO's 2020 Electricity Statement of Opportunities (ESOO)(3).
Capital expenditure	COVID-19 has caused delays in the delivery of network capital expenditure in 2019/20 and may also result in further delays into 2020/21. At this time we anticipate that we will be able to catch-up some of this delay during 2021/22. This is discussed further in Chapter 4 Historical Capital and Operating Expenditure.
Operating expenditure	We have adjusted maintenance practices in 2019/20 in response to the pandemic and some routine maintenance activities have been replaced with condition-based maintenance activities, particularly in areas where it was possible to travel. The main impact from COVID-19 on operating expenditure has been in the balance of expenditure between categories. This has influenced the choice of our operating expenditure base year (refer Chapter 6 Forecast Operating Expenditure).
Insurance	Our insurance brokers, Marsh, have highlighted the unprecedented impact of COVID-19 on the global insurance industry(4). This includes significant potential upward pressure on premiums, which we will need to actively manage in the 2023-27 regulatory period (refer Chapter 6 Forecast Operating Expenditure).

(1) Statement on Monetary Policy November 2020, Reserve Bank of Australia, page 1.

(2) Queensland Budget 2020-21, Queensland Government, December 2020, pages 34-35.

(3) 2020 Electricity Statement of Opportunities, Australian Energy Market Operator, August 2020.

(4) Minutes of the June 2020 Revenue Proposal Reference Group (RPRG) meeting, https://www.powerlink.com.au/2023-27-regulatory-period.

2.5 Energy market drivers

As the NEM continues to transition towards a new energy future, we must navigate a highly dynamic and uncertain environment. The transmission system has changed from one which transports electricity from a small number of large centralised generators to major loads and distributors, to a system that interconnects increasing numbers of generators, loads and storage and transports energy to where it is needed. More homes and businesses also generate their own power through DER technology.

Our annual stakeholder perception survey, undertaken by Deloitte, surveyed 115 of our customers and stakeholders. A summary of the results of this survey for 2020 is included in Appendix 3.06. The survey found that the rapidly changing energy system is a primary concern. A key issue for many of our generator and directly-connected customers was the management of an energy system in transition, in particular system strength. We intend to take a more active role in guiding the Queensland market through this transition. We will adopt an increased focus on planning the broader energy system (generation, energy storage and transmission), undertake more proactive engagement with AEMO and Queensland market participants on key issues and risks in the energy transition, and provide increased support for the Queensland Government in the formulation of future energy policy.

Between 2018 and 2020, we developed our 30 year Network Vision[2] with input from customers, stakeholders and energy industry experts. The aim of our Network Vision is to provide a long-term view across a range of plausible scenarios and understand what services future customers will value. Our Network Vision has informed our Revenue Proposal.

We have further developed the broad themes of our Network Vision – changing electricity consumption patterns, a lower carbon future and decentralised energy sources – into the 'four Ds' discussed in this section:

- decarbonisation;
- decentralisation;
- demand disruption; and
- digitisation.

2.5.1 Decarbonisation

Queensland is in transition to a low carbon future. More than 1,600MW of large-scale renewable generation capacity has been added to the transmission network since 2016. In addition, more than 3,000MW of rooftop solar has been installed at the distribution network level across Queensland.

Figure 2.2 shows the number of completed and committed transmission-connected renewable generation projects as at December 2020. This is provided as context and it is important to note these are non-regulated projects and are therefore not included in our Revenue Proposal expenditure forecasts.

[2] Network Vision, Powerlink, https://www.powerlink.com.au/network-vision.

Figure 2.2: Transmission connections – solar, wind, battery

A higher proportion of renewable generation presents technical challenges in keeping electricity supply and demand balanced, and creates complexity in how we operate and plan the network.

We are involved in joint planning with Distribution Network Service Providers (DNSPs) Energex and Ergon Energy on generator connections within the distribution network that may impact transmission network performance or constraints.

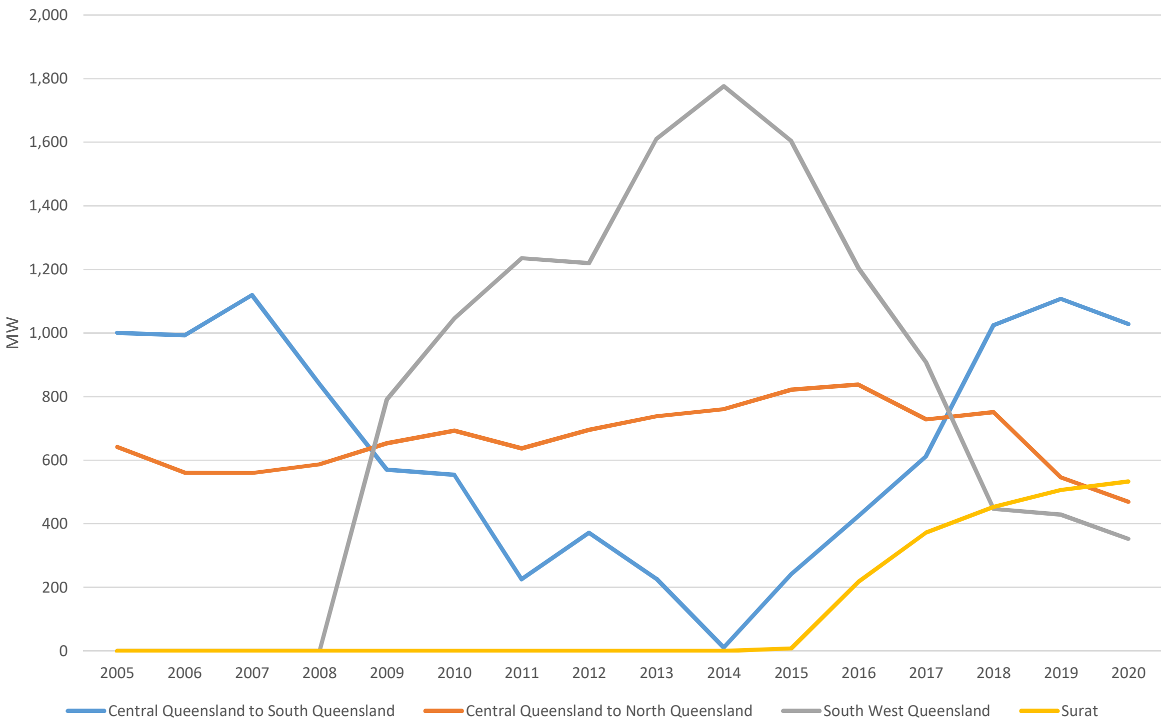
System strength has emerged as a prominent challenge in Queensland (particularly in North Queensland) as well as other parts of the NEM. We are working with customers, regulators, project proponents, suppliers and AEMO to identify, understand and appropriately respond to these challenges.

We have also had regard to AEMO's 2020 ISP. There are currently no 'actionable' projects within the 2023-27 regulatory period under AEMO's ISP. However, one of the key projects identified in the ISP that is currently targeted for completion around 2032 is Queensland/New South Wales Interconnector (QNI) Medium, which involves upgrades to the QNI. Construction of this project would need to commence in the late 2020s, which requires the acquisition of new transmission line easements in the 2023-27 regulatory period (refer Chapter 5 Forecast Capital Expenditure).

2.5.2 Decentralisation

The change in generation mix creates challenges in the operation of our network. Rapid installation of renewables and the forecast closure of ageing coal generation assets across the NEM have driven large changes in power flows across the network, as seen in trends in flows over time in Figure 2.3. This introduces a high degree of uncertainty around the need for investment in major transmission network flow paths.

Figure 2.3: Average annual power flow across major transmission flow paths (MW)



The increasingly constrained network flow from Central Queensland to Southern Queensland (CQ-SQ) is an example of the level of uncertainty that exists and the difficulties we face in planning the network. As shown in Figure 2.3, power flow gradually declined until 2014. Since then CQ-SQ has seen a significant increase in power flows, driven by the investment in new renewable generation in North Queensland.

This part of the network now experiences regular capacity constraints, which means the cheapest sources of electricity cannot always be delivered to customers. Electricity market constraints also impact our ability to effectively manage necessary outages on the network in a way that minimises impacts to network users. A reduced window to schedule outages places pressure on how and when we can deliver capital works, and operate and maintain the network.

An upgrade of the CQ-SQ network is flagged for the early 2030s in AEMO's 2020 ISP. However, subsequent renewables development in southern Queensland or northern New South Wales (NSW) could again fundamentally shift intra-connector flows. Given the uncertainty related to the investment need for CQ-SQ and the timing of any investment need being potentially late in the 2023-27 regulatory period or early in the following regulatory period, our Revenue Proposal includes some (limited) capital expenditure for targeted life extension works on this part of the network.

The CQ-SQ network is a key example of why we consider the concept of contingent reinvestments should be pursued further, outside the current Revenue Proposal process. The rapid changes occurring through the energy transition can make it highly uncertain whether existing network capacity along major transmission flow paths should remain the same, be increased, or even be reduced, which must be considered as part of any potential asset reinvestment along those flow paths. Rather than ask customers to pay for investments that remain highly uncertain, we would have a mechanism to seek approval from the AER should such expenditure be required to maintain the safe, secure, reliable and cost-effective supply of electricity within the regulatory period.

It is clear that as we transition to this new energy future, investment will need to take a 'whole of system' perspective. This will require greater coordination of investment strategies between generation, transmission and distribution businesses to deliver appropriate outcomes for our customers.

2.5.3 Demand disruption

Solar uptake at a household level continues to drive changes to our demand and energy patterns. Overall, while energy consumption is declining, several key trends have been observed across our network.

Higher and shorter demand peaks

Maximum demand is expected to grow at 0.7% per annum over the next 10 years[3] (refer Chapter 5 Forecast Capital Expenditure). Increases in peak demand puts pressure on the maximum capacity of our network, which would traditionally necessitate network augmentation investment. However, the short duration and low frequency of these maximum demand events makes network augmentation uneconomic.

This reduction in demand-driven investment has occurred in the current regulatory period, and is expected to continue in the 2023-27 regulatory period. We have proposed only one capital project (estimated at $2.4m) driven by increased maximum demand in our Revenue Proposal.

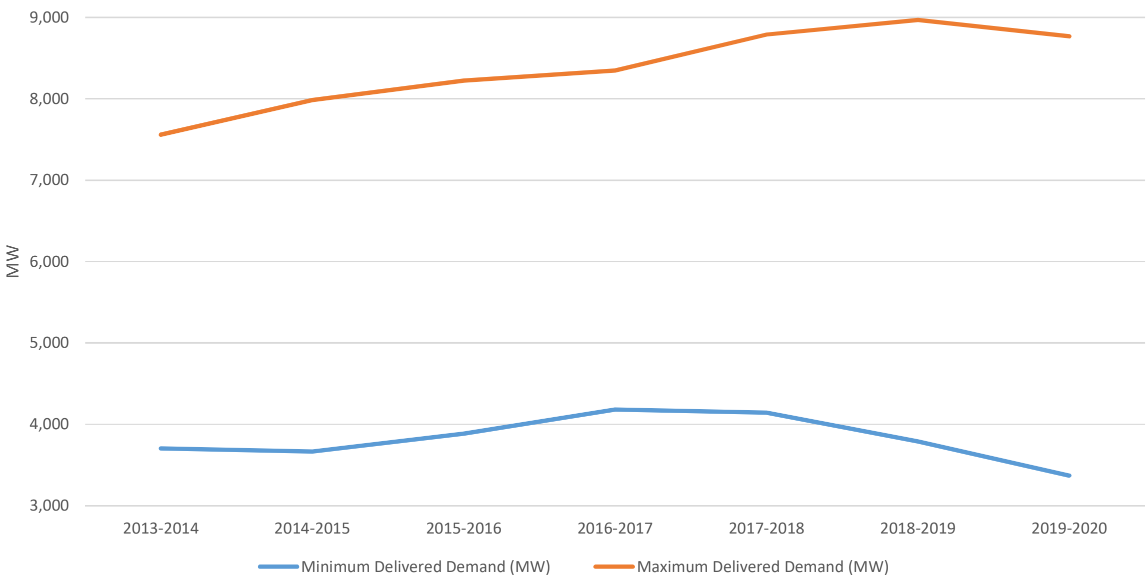
Decline in minimum demand

Demand during the day has reduced to levels (currently approximately 3,500MW) that impact on the technical capability for daytime baseload generation to operate. This is driven by the increased deployment of DER, which includes large-scale photovoltaic (PV) generation connected to distribution networks and customer rooftop PV. AEMO forecasts that minimum operational demand is expected to continue to fall by 1.9% per annum in Queensland between 2021 and 2040[4].

While minimum demand has declined and will continue to decline, significant transmission connected generation is still required to meet peak demand. These opposing factors mean it is increasingly difficult to determine the optimal investment strategy (e.g. life extension, replacement or other reinvestment options) for some transmission network assets, or whether they could potentially be decommissioned.

Figure 2.4 demonstrates these inverse trends.

Figure 2.4: Trends in Maximum and Minimum Delivered Demand in Queensland (MW)



In the near-term, this rate of decline in minimum demand could be greater than the long-term average as Queensland continues to experience rapid uptake of rooftop solar PV systems, particularly from larger sized commercial installations. An increased spread between minimum and maximum demands is likely to present operational challenges for both AEMO and network businesses in managing the demand for various forms of system services.

3 2020 Electricity Statement of Opportunities, Australian Energy Market Operator, August 2020.
4 *Ibid*, page 43.

As battery storage technology further develops, it also has the potential to flatten electricity usage and reduce the need to develop transmission services to cover short duration peaks. We may also see an increase in the application of batteries to reduce residential demand peaks as customers take advantage of storage to smooth their consumption and avoid peak retail tariffs. Government policy, retail offerings, development of community storage or large-scale storage and demand response are also factors that may influence minimum demand in the future.

For Powerlink, the issue of an increased spread between minimum and maximum demands is driving the need to install additional reactive power control devices to maintain power system voltages within secure limits. Our capital expenditure forecast includes $22.4m in investment for these devices to support prescribed transmission services (refer Chapter 5 Forecast Capital Expenditure).

If the decline in minimum demand turns out to be materially greater than is currently forecast by AEMO it could necessitate further investment in the provision of system services for prescribed purposes. This could be either through direct investment in new assets, or through mechanisms such as cost pass through arrangements and contracts for network support services (refer Chapter 12 Pass Through Events). Relevant capital investments will also be subject to the AER's Regulatory Investment Test for Transmission (RIT-T).

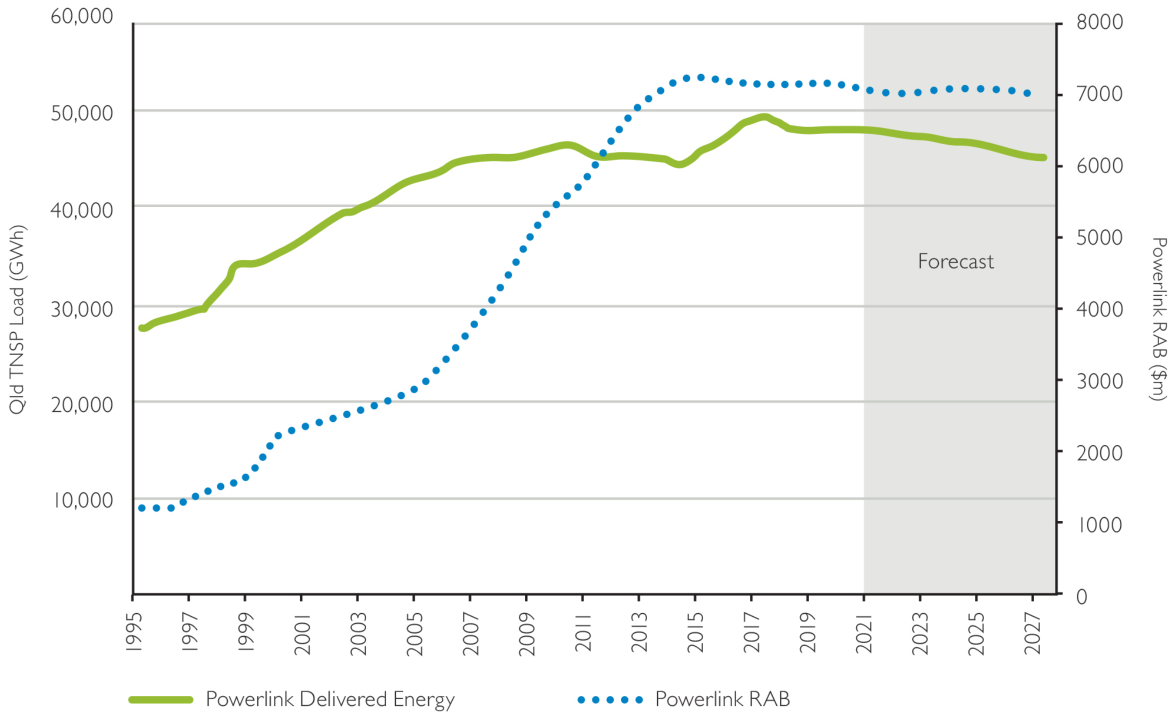
Decline in delivered energy

Total delivered energy is expected to decline at an average annual rate of 0.7% over the next 10 years[5] (refer Chapter 5 Forecast Capital Expenditure). This is primarily due to current and proposed large-scale renewable generation that is (or will be) directly-connected to the distribution network.

In line with flat or declining forecasts of delivered energy, our RAB has decreased in both nominal terms and real terms in the current regulatory period[6].

In the 2023-27 regulatory period, we forecast our RAB to continue to decrease in both nominal and real terms[7] (refer Chapter 8 Regulatory Asset Base). Our proposed reduction in capital expenditure has contributed to this decrease, and we consider the trend in our RAB provides a reasonable indication of our prudent asset management and reinvestment approach.

Figure 2.5: Powerlink forecast delivered energy (GWh) versus RAB ($m nominal)



5 2020 Electricity Statement of Opportunities, Australian Energy Market Operator, August 2020.
6 Based on a comparison of 1 July 2017 opening RAB to 30 June 2022 closing RAB.
7 Based on a comparison of 1 July 2022 opening RAB to 30 June 2027 closing RAB.

2.5.4 Digitisation

The growth in the number and interconnectedness of digital sensors and mobile devices is often referred to as the Fourth Industrial Revolution[8]. The first and second industrial revolutions entailed the harnessing of mechanical and electrical energy to replace manual work. The third industrial revolution harnessed the power and cost benefits of digital technologies to collect data from the real, analogue world and transform it into digital form. Once in digital form the data can be assembled and communicated at near zero cost and provides the basis for improvements in production and operations processes.

The transformation of data into information and then insights can improve business decision-making and reduce risks to our customers. Our investments in Business Information Technology (IT) and Operational Technologies are made to ensure we can deploy and access enhanced digital data analytics to support the business and the provision of services to customers. This includes digital interfaces with our customers, our suppliers and AEMO.

Our key business initiatives that support this increase in digitisation are:

- Next Generation Network Operations (NGNO) – our program to modernise our network operations and be able to adapt to the changing energy landscape. A foundational element is a new advanced Energy Management System to support our real-time operations.
- Systems, Applications, Products (SAP) Transform – the replacement of our legacy Enterprise Resources Planning system will support increasing digitisation and automation of routine business processes.

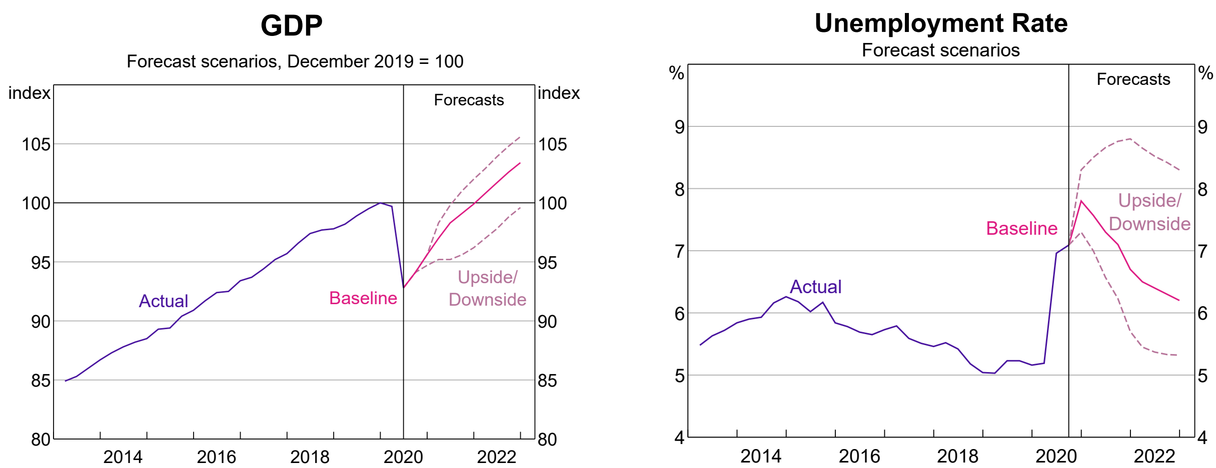
2.6 Economic and financial market drivers

The COVID-19 pandemic is currently the dominant influence on the economy and financial markets and remains the main source of uncertainty for the economic growth outlook.

The Reserve Bank of Australia (RBA) describes the COVID-19 pandemic as the largest shock to the global economy in many decades[9]. The RBA recently observed that the 7% contraction in Gross Domestic Product (GDP) in the June quarter was the largest and one of the most sudden in peacetime since the 1930s[10]. It has also resulted in significant disruption to the labour market. While labour market conditions have also improved, the RBA expects significant excess capacity to remain. This will continue to drive low wages growth and inflation.

The global economy, along with Australia, is currently in the early stages of recovery, although the RBA sees this as fragile and uneven[11]. Given the extreme uncertainty that has arisen from the pandemic, the RBA considers the outlook in terms of three scenarios. Under its baseline scenario, the economy is forecast to contract by around 4% for the year to December 2020, followed by growth of 5% in 2021 and 4% in 2022. Unemployment is forecast to peak at 8% by the end of 2020[12]. The RBA scenarios for GDP growth and unemployment are shown in Figure 2.6.

Figure 2.6: RBA scenarios: GDP and unemployment (Australia)



Source: Statement on Monetary Policy November 2020, Reserve Bank of Australia, pages 81-82

8 The Fourth Industrial Revolution – What it means and how to respond, Klaus Schwab, Foreign Affairs, December 2015.
9 Statement on Monetary Policy August 2020, Reserve Bank of Australia, page 1.
10 Statement on Monetary Policy November 2020, Reserve Bank of Australia, page 1.
11 *Ibid*, page 79.
12 *Ibid*, page 1.

In the Queensland Budget 2020/21, the Queensland Government forecast a marginal increase of 0.25% in GSP in 2020/21, a rebound to 3.5% growth in 2021/22 and then a return to longer-run growth potential of around 2.75% per annum[13]. This assumes that COVID-19 remains contained.

Overall, this highlights considerable uncertainty domestically and globally. This outlook has had a direct impact on the demand for electricity in the short-term, which may continue into the medium and long-term. It has also impacted key assumptions that underpin our Revenue Proposal such as inflation, labour cost escalators and elements of our rate of return.

We are also mindful of the impact of COVID-19 and the current economic climate on affordability, which is discussed in sections 2.3.1 and 2.4. More broadly, a sustained low economic growth environment could impact the financial sustainability of our suppliers and supply chains, thus impacting our ability to deliver projects on time and on budget.

A delivery and skills resource risk is also expected over the 2023-27 regulatory period. Australia has a limited pool of skilled labour for large electricity infrastructure investments, and there is a potentially significant period of transmission work to occur across the NEM. This is particularly the case if proposed projects in the 2020 ISP proceed as planned, in addition to the replacement of older transmission network infrastructure that needs to occur in the next decade. This will coincide with major infrastructure investment across the economy.

This work is in addition to existing capital and operating expenditure work. We have engaged with other Transmission Network Service Providers (TNSP) as to how this risk can be managed, which could include:

- development of project timelines and resource requirements by skill sets;
- management of the balance between internal and external resources, as well as augmentation versus replacement works; and
- identification of the need for increased levels of specific skills, which can be addressed by apprenticeships and training programs.

Competition for scarce resources may influence the cost of our projects, in particular capital projects, and we will need to manage this impact if it arises.

2.7 Government policy and regulation

This section outlines potential changes in our regulatory environment and the potential impact of government policies on our Revenue Proposal.

2.7.1 Energy market regulation

Key regulatory consultations underway that could significantly impact the provision of electricity transmission services include the Coordination of Generation and Transmission Investment reforms, the Energy Security Board's Post 2025 Market Design, Transmission Ring-Fencing Review and the Energy Security Board's consultation on planning rules for Renewable Energy Zones (REZs). The outcome of the AER's review of its regulatory treatment of inflation is also important as it will impact our revenue and prices within the regulatory period.

The outcomes of these regulatory reforms could have material impacts on our operations, such as changes to funding models for future network investment and the way revenue is collected. Until the outcomes from these reviews are finalised, it is unclear how they may impact our regulatory and other obligations going forward. For example, the AER's review of its Transmission Ring-Fencing Guideline could fundamentally impact the way in which we deliver our transmission services.

Until such time as we know the scope and scale of any changes to the existing arrangements, it will be difficult to estimate the cost impacts on the business. As a result, we have not allowed for this in our operating expenditure forecast (refer Chapter 6 Forecast Operating Expenditure). If material costs are likely to be incurred, we may seek a cost pass through within the regulatory period (refer Chapter 12 Pass Through Events).

2.7.2 Federal and Queensland Government policies

Government energy policies establish broad frameworks that can have important implications for market participants and customers (e.g. the Queensland Government's 50% Renewable Energy Target or the Federal Government's Low Emissions Technology Statement 2020). Key policies and decisions that may impact our Revenue Proposal are outlined in the following section.

[13] Queensland Budget 2020-21, Queensland Government, December 2020, page 40.

Federal Government

There are two Federal Government policies that have been considered as part of our Revenue Proposal:

- the progressive increase to the Superannuation Guarantee rate which is currently targeted to reach 12% from 1 July 2025, which could impact our labour costs and WPI forecasts (refer Chapter 7 Escalation Rates and Project Cost Estimation); and
- the *Security Legislation Amendment (Critical Infrastructure) Bill 2020*, which was introduced to Parliament in December 2020 but has not yet passed, would establish a new security and resilience regulatory regime on operators of critical infrastructure. We anticipate additional security (including cyber security) obligations for critical infrastructure providers as a result of this new legislation (refer Chapter 6 Forecast Operating Expenditure).

Queensland Government

The Queensland Government has committed to a 50% Renewable Energy Target (RET) by 2030 and has made recent energy policy announcements that focus on regional development, investment to support energy security and COVID-19 economic recovery. This includes potential investment in transmission infrastructure, such as:

- support for Genex's 250MW Kidston pumped storage hydro project[14];
- support for Copperstring 2.0, which would connect the North West Minerals Province to the national grid[15]; and
- other projects that will contribute to the achievement of the Queensland Government's 50% RET. This includes its $145m announcement to unlock three renewable energy corridors in North, Central and South West Queensland[16] and a further $500m to support Renewable Energy Zone (REZ) Development[17].

These initiatives largely rely on market-based responses and do not directly impact our Revenue Proposal. If these investments proceed, they may trigger a need for investment in the prescribed network in the future. However, we have not included any associated expenditure in our forecasts.

We are working with the Queensland Government to understand and progress these initiatives as appropriate and required.

2.8 Environment drivers

Extreme weather events such as cyclones, bushfires and floods create challenges for the operation of the transmission network. The nature, frequency and impact of these events remain extremely difficult to predict and the risks vary across our network. Our approach is to design and construct our assets to be resilient against forecast risks, consistent with prevailing standards and to an extent that is prudent and efficient.

Our network has not been materially impacted to date by recent bushfires or other severe weather events like networks in New South Wales, Victoria and South Australia. We have not forecast capital expenditure to address general weather-related risks over the 2023-27 regulatory period.

In relation to operating expenditure, extreme weather events in Australia and across the world have placed upward pressure on our insurance premiums. We engage directly with insurance underwriters to ensure they understand the circumstances related to our business to advise appropriate insurance policies, excess levels and premiums. We have also consulted on this with our customers and the AER in the development of our Revenue Proposal. Further information on our proposed approach to insurance is provided in Chapter 6 Forecast Operating Expenditure.

2.9 Summary

We are operating in an environment of uncertainty, driven by significant changes in the energy market, the COVID-19 pandemic and potentially long-lasting effects on the national economy. Our customers remain concerned about affordability, and so do we.

We have had regard to our external environment in the development of our capital and operating expenditure forecasts, and the financial elements of our Revenue Proposal. We have actively engaged with our customers to understand their needs, priorities and concerns, and these are reflected in our business and operating environment.

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[14] Statements/88279, Queensland Government, https://statements.qld.gov.au/statements/88279.

[15] Statements/89847, Queensland Government, https://statements.qld.gov.au/statements/89847.

[16] Queensland Renewable Energy Zones, Department of Natural Resources, Mines and Energy, https://www.dnrme.qld.gov.au/energy/initiatives/queensland-renewable-energy-zones.

[17] Statements/90683, Queensland Government, https://statements.qld.gov.au/statements/90683.

3. Customer Engagement

3.1 Introduction

This chapter outlines Powerlink's customer engagement activities and how they influenced and improved decision-making in the preparation of our 2023-27 Revenue Proposal.

Key highlights:

- We are the first network business to co-design our engagement approach with customers and stakeholders. This enabled customers to directly shape the scope, sequencing, techniques and evaluation of our engagement.
- We established a Revenue Proposal Reference Group (RPRG), a subset of our wider business-as-usual Customer Panel, to engage more intensively and deeply on key aspects of our Revenue Proposal and report back to the wider Customer Panel.
- We developed and published a draft Revenue Proposal in September 2020, after encouragement to do so from our Customer Panel and the Australian Energy Regulator's (AER's) Consumer Challenge Panel (CCP23).
- Engagement directly influenced key elements of our Revenue Proposal. In particular, we have responded to feedback and customer concerns about affordability. This includes:
  - **operating expenditure** – we will target no real growth in total operating expenditure compared to actuals/forecast in the current regulatory period. To achieve this target we have proposed, in combination, a higher than industry average productivity factor of 0.5% and have not pursued any step changes;
  - **capital expenditure** – we propose a 3% real reduction in capital expenditure compared to actuals/forecasts in the current regulatory period. We have also decided not to proceed with contingent reinvestment projects after feedback from customers and the AER; and
  - **depreciation** – we proposed a way to smooth the impact on customers arising from our change in depreciation tracking method (refer Chapter 10 Depreciation).
- The input on the above key elements contributed to our proposed reduction in Maximum Allowed Revenue (MAR) of $587.4m (15%) compared with our allowed MAR for the 2018-22 regulatory period. This results in a drop of 11% in average transmission prices in the first year of the next regulatory period (2022/23), and for price growth over the remainder of the regulatory period to be in line with inflation. For average residential and small business customers, this represents an estimated saving in the first year of $13 and $23, respectively. This is on the basis of assumed tariffs and consumption[1].

3.2 Capable of acceptance

3.2.1 Engagement goal

Our engagement approach for the Revenue Proposal is driven by our overarching goal to deliver a Revenue Proposal that is capable of acceptance by our customers, the AER and Powerlink. This goal targeted acceptance of our Revenue Proposal as an overall package by relevant stakeholders *at the time we lodged our Revenue Proposal* with the AER in January 2021. This is an important distinction from what some stakeholders may have assumed, which is capable of acceptance by the end of the AER's 15-month formal review process.

To achieve this goal we recognised the need to engage early, deeply on key issues and often. Early engagement allowed us to share our initial thinking, enabled customer input to shape this and for both parties to listen, learn and grow from the interactions. Deeper engagement on key issues of importance to customers, the AER or our business created greater awareness and understanding of the issues, trade-offs and the consequences of taking various courses of action. The frequency with which we met provided regular opportunities for us to demonstrate our commitment to a 'no surprises' approach to engagement, to build rapport and trust, and to show how we operate our business.

Our engagement goal and overall approach is outlined in Appendix 3.01 Engagement Plan.

[1] The transmission component of electricity bills is based on information from the Australian Energy Market Commission (AEMC) Electricity Price Trends Report, December 2020. Assumed residential consumption is based on the Queensland Competition Authority's (QCA) annual Tariff 11 (residential) median energy usage of 4,061kWh p.a. Assumed small business consumption is based on the QCA's annual Tariff 20 (small business) median energy usage of 6,831kWh p.a.

Draft Revenue Proposal

We recognised the need to adapt our engagement approach in light of stakeholder feedback, particularly where it would provide meaningful value to our customers. As it turns out, a key milestone in our engagement was one that was not on our plan at the start. That is, the development and publication of our draft Revenue Proposal in September 2020.

A draft Revenue Proposal is not a formal requirement of the National Electricity Rules (the Rules) and we originally did not plan to release one. However, based on constructive engagement with our customers and the AER during 2020, we decided to prepare and publish a draft version of our Revenue Proposal for input in September 2020.

We considered that publication of our Revenue Proposal in draft form would further promote the transparency of our engagement and would enable our stakeholders to see in 'black and white' where our business was heading, why and how we had responded to issues raised to date.

While we have actively encouraged input and participation from our customers, the AER and CCP23 every step of the way, the draft Revenue Proposal provided another, perhaps more formal opportunity for stakeholders to provide feedback. In hindsight, we consider that this was an important step (albeit unplanned and challenging to deliver at the time), which demonstrated that we were serious about developing a Revenue Proposal that was capable of acceptance by customers, the AER and Powerlink at the time we lodged our Revenue Proposal in January 2021. It also reinforced our commitment to taking a 'no surprises' approach to our engagement.

Our draft Revenue Proposal is published on our website[2] and we have included submissions received in Appendix 3.02 Submissions on our draft Revenue Proposal[3].

3.2.2 Capable of acceptance criteria

In our draft Revenue Proposal, we proposed to utilise the criteria outlined in Table 3.1 from CCP24[4] in the context of its advice to the AER on another regulatory determination process. This was intended to help customers and the AER assess whether our Revenue Proposal was capable of acceptance.

Table 3.1: CCP24 capable of acceptance criteria

Criteria
Demonstrated customer support
Engagement was meaningful and the business was responsive to feedback
A clear business narrative was provided
Affordability was considered and addressed
The business assessed options available to it and sought to provide value to customers
The Revenue Proposal is reasonable comparative to past performance and Transmission Network Service Provider (TNSP) peers
Follows relevant AER guidelines and regulatory models (AER to assess)
Forecast capital and operating expenditure is prudent and efficient (AER to assess)

After further engagement with our Customer Panel, the AER's CCP for our revenue determination process (sub-panel CCP23) and the AER, we have decided to use the Framework for Considering Consumer Engagement as the criteria for capable of acceptance. This framework was published in the AER's September 2020 Draft Decisions for the Victorian Distribution Network Service Providers (DNSPs)[5].

We have assessed ourselves against the framework, which is set out in Section 3.2.3. We also asked our Customer Panel to provide an assessment, which is discussed in Section 3.2.4 and in Appendix 3.03 Customer Panel Statement on Engagement. We encourage and welcome an assessment from the AER and AER's CCP23 as part of their consideration of our Revenue Proposal.

2 Draft Revenue Proposal, Powerlink, https://www.powerlink.com.au/2023-27-regulatory-period.
3 Submissions were received from our Customer Panel, AER CCP23 and Shell.
4 CCP24 was the relevant CCP for Australian Gas Networks determination. Refer to advice to the AER on Australian Gas Networks Final Plan, CCP24, August 2020.
5 Overview, Section 3, Table 7 in the Draft Decisions for AusNet Services, Jemena, United Energy, CitiPower and Powercor, Australian Energy Regulator, September 2020.

3.2.3 Self-assessment against capable of acceptance criteria

The following table outlines our self-assessment against the capable of acceptance criteria. For clarification, the criteria and example columns set out in Table 3.2 were used by the AER in the context of its Draft Decisions for other network service providers[6].

Table 3.2: Framework for Considering Consumer Engagement criteria

Criteria	Examples of how this could be assessed	Powerlink self-assessment against criteria
Nature of engagement	• Customers partner in forming the proposal rather than asked for feedback on the proposal. • Relevant skills and experience of the customers, representatives and advocates. • Customers provided with impartial support to engage with energy sector issues. • Sincerity of engagement with customers. • Independence of customers and their funding. • Multiple channels used to engage with a range of customers across Powerlink's customer base.	• Co-design approach to set engagement approach, scope, techniques and evaluation (refer Section 3.3.3). • Highly experienced Customer Panel, with many involved since 2015. Several are also members of the AER's Consumer Challenge Panel (refer Section 3.5). • Feedback on engagement confirms it has been genuine, open and authentic (refer Section 3.9). • Wide range of engagement channels used including Customer Panel meetings, RPRG meetings, large forums, webinars, deep dives, one-on-one briefings, social media and website (refer sections 3.6 and 3.7). • Terms of Reference for the RPRG, included in Appendix 3.04, outlined funding to members to undertake independent research and outlined non-financial support mechanisms.
Breadth and depth	• Clear identification of topics for engagement and how these will feed into the Revenue Proposal. • Customers consulted on broad range of topics. • Customers able to influence topics for engagement. • Customers encouraged to test the assumptions and strategies underpinning the proposal. • Customers were able to access and resource independent research and engagement.	• Clear engagement scope co-designed with customers up-front, on the basis of the impact on MAR (refer Section 3.4). • A calendar of potential topics and dates for engagement was provided at the beginning of the RPRG process. • Engagement scope was regularly updated based on customer feedback. Demonstrated by several updates to the Engagement Plan (refer to Appendix 3.01 and table in Section 3.4). • Customers were encouraged to provide input and feedback during and outside meetings. • Customer Panel members stated(1): o The panel are unanimous in our view that Powerlink's engagement with us has been genuine, consistent and deep. We also acknowledge the consistent high-level efforts of Powerlink staff to ensure that they engage meaningfully with us. • Two Customer Panel meetings were organised without Powerlink representatives present to allow frank discussion on the draft Revenue Proposal, engagement evaluation and capable of acceptance criteria. • With regard to customers being able to access and resource independent research and engagement, refer to the comment in the table above on the Terms of Reference for the RPRG.
Clearly evidenced impact	• Proposal clearly tied to expressed views of customers. • High level business engagement (e.g. customers given access to Powerlink's Chief Executive and/or Board). • Powerlink has responded to customer views rather than just recording them. • Impact of engagement can be clearly identified. • Submissions on proposal show customers feel the impact is consistent with their expectations.	• Influence of engagement clearly visible through changes in key aspects of the Revenue Proposal over the progressive development of five sets of expenditure and revenue forecasts (refer Section 3.8), and in our Revenue Proposal. • Active involvement in engagement activities by our Chair, Board, Chief Executive and Executive Team. Customer feedback was communicated regularly to the Board and Executive Team to inform decision-making. • Detailed minutes of Customer Panel and RPRG meetings demonstrate publicly how feedback has influenced decision-making (refer Section 3.8). • In their Statement on Engagement(2) our Customer Panel said there were a number of cases where they felt they influenced the Revenue Proposal and that their level of influence was high, relative to other engagement processes in the industry.

[6] *Ibid.*

Criteria	Examples of how this could be assessed	Powerlink self-assessment against criteria
Proof point	• Reasonable opex and capex allowances proposed, for example: o In line with, or lower than, historical expenditure. o In line with, or lower than, the AER's top-down analysis of appropriate expenditure. o If not in line with top-down, can be explained through bottom-up category analysis.	• We propose a 3% real reduction in capital expenditure compared to actual/forecast in the current regulatory period (refer Chapter 5 Forecast Capital Expenditure). • We propose a target of no real growth in underlying operating expenditure compared to actual/forecast in the current period for 2023-27 regulatory period (refer Chapter 6 Forecast Operating Expenditure). • Our Regulatory Asset Base (RAB) is reducing in both real and nominal terms (refer Chapter 8 Regulatory Asset Base). • Our proposed MAR is 15% lower than in the current regulatory period. • We forecast a reduction in the indicative transmission price in the first year of the next regulatory period of about 11% in nominal terms. Average price growth is expected to remain within inflation for the remainder of the regulatory period (refer Chapter 11 Maximum Allowed Revenue and Price Impact).

(1) Appendix 3.03 Customer Panel Statement on Engagement.

(2) Appendix 3.02 Submissions on our draft Revenue Proposal.

3.2.4 Customer assessment against capable of acceptance criteria

We strongly encouraged our Customer Panel to provide an assessment of our engagement approach and whether our Revenue Proposal is capable of acceptance, based upon the engagement we undertook in the development of our proposal and the information made available to them over that time. This direct evaluation from our Customer Panel will help us identify where our engagement has been successful and where we could improve. It is also important feedback that should be considered by the AER and the AER's CCP23 as part of their assessment of our Revenue Proposal.

In December 2020, our Customer Panel met (without Powerlink staff present) to discuss the concept of capable of acceptance and to evaluate our engagement approach.

The majority of panel members were of the view that our Revenue Proposal was reasonable. However, they also felt they did not have the skills or grounding to be able to make a formal judgement about whether the proposal is capable of acceptance.

Members commented that Powerlink should have clarified what capable of acceptance meant with the AER first, so that panel members had a clearer target to judge against. Members also noted that the AER is still in the process of developing its own detailed understanding of what capable of acceptance means. In addition, the Panel considered that a capable of acceptance judgement could be made at a later stage, potentially after a review of the Revenue Proposal or the AER's Draft Decision.

We appreciate that it may be difficult for customers to state unconditionally whether our Revenue Proposal is capable of acceptance prior to its lodgement. We intend to undertake further engagement post-lodgement in response to this feedback to try to achieve our overarching goal to deliver a Revenue Proposal that is capable of acceptance by our customers, the AER and Powerlink.

The Customer Panel's Statement on Engagement is included in full in Appendix 3.03.

3.3 Our engagement approach

3.3.1 Overview

We are committed to genuine and timely engagement to inform our decision-making as part of our normal business operations. It is fundamental to the way we do business and has led to better outcomes for our customers and stakeholders. This aligns with our commitment to the Energy Charter principles[7], in particular Principle One - *We will put customers at the centre of our business* and Principle Two - *We will improve energy affordability for customers.*

As our operations extend across Queensland, we engage with a diverse range of stakeholders in the normal course of business. This includes our customers, landholders, environmental and community groups, government agencies and industry bodies.

[7] The Energy Charter, https://www.theenergycharter.com.au.

Our engagement is designed to create a shared understanding of our business decisions and the trade-offs involved in making them (e.g. cost, reliability). Some of the key avenues through which we engage as part of business-as-usual[8] activities include:

- our Customer Panel, which met regularly over the past five years and provides input on our activities to inform our decision-making across a broad range of areas (e.g. on Regulatory Investment Test for Transmission (RIT-T) assessments, transmission pricing, our 30 year Network Vision and our Information Technology Benefits Realisation Framework);
- our annual Transmission Network Forum, which is our flagship engagement activity and typically involves more than 200 stakeholders and customers;
- targeted webinars and workshops on RIT-T assessments, regional developments and demand and energy forecasts;
- dedicated landholder engagement through our landholder relations team to ensure land access and engagement practices are aligned with expectations; and
- regular briefings to local governments across Queensland about our operations in their areas.

We apply an open and transparent approach to our engagement with customers and the AER in the normal course of business. This approach has naturally extended to the preparation of our Revenue Proposal.

3.3.2 Revenue Proposal engagement key principles

To support engagement on our Revenue Proposal, we established a set of key engagement principles:

- ***Active Engagement:*** Actively involve customers and stakeholders in developing and refining our engagement approach.
- ***Appropriate Influence:*** Engage at the appropriate level of the International Association for Public Participation (IAP2) Spectrum so that customer and stakeholder feedback appropriately influences decisions.
- ***Plan Ahead:*** Communicate timings for key engagement activities well in advance to maximise participation by customers and stakeholders.
- ***Efficient Scope:*** Ensure scope leads to efficient engagement by discussing the elements of Powerlink's Revenue Proposal that have the greatest ability to be influenced and a significant impact on MAR or improvement of outcomes.
- ***Appropriate Resourcing:*** Provide education and funding support to allow customer representatives to undertake independent research and reviews if required.
- ***Accessible Information:*** Present information in a clear and accessible manner so that customers and stakeholders can meaningfully participate in engagement activities and provide informed feedback.
- ***Demonstrate Impact:*** Demonstrate how engagement has changed Powerlink's position throughout the process by regularly communicating with customers and stakeholders about how their feedback was taken into account.

3.3.3 Co-design approach

We are the first network business to co-design our Revenue Proposal engagement approach with our customers and stakeholders. We also invited the AER to participate in this process.

Customers, advocates and stakeholders collaborated with members of our Board, Executive Team and other staff at a co-design workshop in May 2019 to shape our:

- overarching engagement approach;
- engagement scope;
- engagement techniques;
- engagement sequencing;
- communications to support engagement; and
- engagement evaluation.

Following the workshop we prepared a draft Engagement Plan and circulated this to customers and workshop attendees for further input. Our Engagement Plan was published in September 2019, with minor updates between May and September 2020. A further updated version was published in December 2020 to reflect additional engagement undertaken and is included as Appendix 3.01.

[8] Stakeholder Engagement, Powerlink, https://www.powerlink.com.au/stakeholder-engagement.

3.3.4 Engagement approach key elements

Our engagement approach is built on four foundational elements, shown in Figure 3.1. These reflect feedback received from customers and stakeholders about what comprises successful engagement on a Revenue Proposal. We explain our approach to each element in the following sections.

Figure 3.1: Engagement foundational elements

Fit-for-purpose

We used an engagement approach that aligns with our business, customer and stakeholder needs. We leveraged off business-as-usual engagement activities and worked closely with our existing Customer Panel, the AER and the AER's CCP23.

Since our Customer Panel was established in May 2015, we have worked closely with its members to improve their knowledge of the transmission industry, the regulatory framework and our operations. In return, our Customer Panel has played a primary role in influencing our Revenue Proposal given their long-standing involvement with our business.

After input from customers and stakeholders, we used an Expression of Interest process to form our RPRG, which comprises five members of our existing Customer Panel. This was in line with feedback from co-design workshop participants, whose preference was to not establish a negotiating panel separate to our existing Customer Panel.

This approach enabled us to engage in more detail, and more regularly, with a smaller, targeted group. Since its establishment in October 2019, the RPRG has considered and provided input on key aspects of our Revenue Proposal on an almost monthly basis and has met 10 times in total. Members of the RPRG also reported back on progress to the broader Customer Panel.

We also actively encouraged participation by the AER and AER's CCP23 in our engagement activities, such as Customer Panel and RPRG meetings, and our Transmission Network Forum.

Create a clear Business Narrative

In response to customer and stakeholder feedback, we developed a Business Narrative document in January 2020 to provide broader context to our Revenue Proposal and assist customers (directly-connected and end-user representatives) and stakeholders (government and industry) to participate more effectively in our engagement activities. Our Business Narrative is included in Appendix 2.01.

Our Business Narrative included our long-term view about our operations, challenges and opportunities and how we plan to deliver better value for our customers. It was informed by a range of different internal and external plans and strategies, as well as our 30 year Network Vision.

Consistent with our Engagement Plan, we updated the Business Narrative twice. Our first update was in February 2020, to reflect the needs and priorities of our customers and stakeholders. We updated the Business Narrative a second time in April 2020 to reflect the impact of COVID-19 on our operating environment. While we have not updated the Business Narrative for our Revenue Proposal again, the information included in Chapter 2 Business and Operating Environment is intended to provide the latest information around needs and priorities.

Seek early involvement from the AER

To achieve our engagement objective, we sought early involvement from the AER to provide input and feedback on key aspects of our Revenue Proposal.

We engaged initially with AER staff in May and June 2019 to discuss Powerlink's engagement approach and forecasting methodologies. We met monthly with AER staff from October 2019 to discuss the development of key aspects of our Revenue Proposal, and held more in-depth, issue specific meetings where needed. We also provided early versions of our models to the AER in August 2020 and September 2020 for review. We considered AER and AER CCP23 feedback on materials and models and adjusted where relevant.

We also engaged on a monthly basis with the AER's CCP23 and had open discussions about the progress of our engagement activities as well as any queries they had as a result. We regularly encouraged CCP23 input and participation.

AER staff and the CCP23 attended RPRG meetings and, where appropriate, responded to queries from RPRG members and Powerlink staff. The AER and AER CCP23's role in engagement is important as other customer and stakeholder representatives rely on their analysis to gain confidence on the more technical elements of a Revenue Proposal.

Apply a transparent and rigorous approach

We committed to, and applied, rigorous engagement protocols for our RPRG meetings, as outlined within our RPRG Terms of Reference[9]. We developed detailed minutes and a one page overview on each of our RPRG meetings. We sought input from attendees before publishing these materials on our website as final to ensure we accurately reflected their input.

We have demonstrated transparency in the development of our Revenue Proposal through publication and engagement on five separate rounds of forecasts of MAR, RAB, rate of return, operating expenditure, capital expenditure and expenditure incentive schemes, between December 2019 and November 2020. Each round of forecasts included details about changes since the previous forecast and we highlighted how customer and stakeholder feedback had influenced outcomes.

In December 2020 we provided an update on further progress and key outstanding matters. We also provided our Customer Panel, the AER and AER CCP23 with our updated final forecasts in January 2021 prior to lodgement of our Revenue Proposal with the AER.

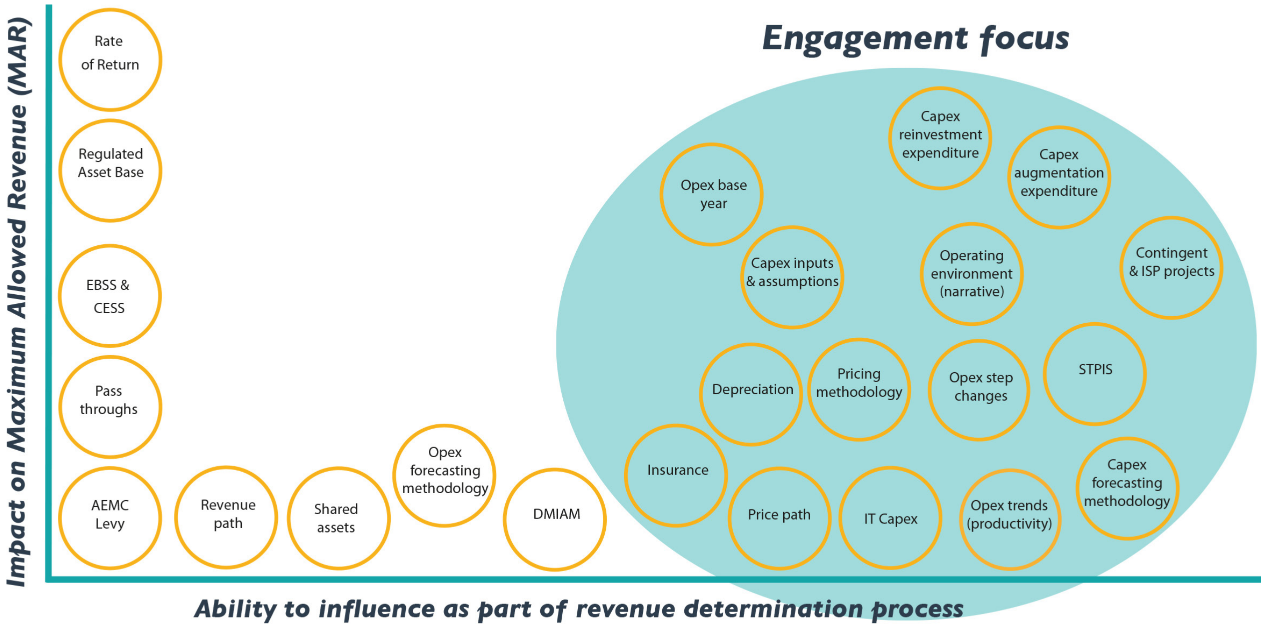
3.4 Engagement scope

We understand that customer and stakeholder representatives are time poor and resource constrained. Providing a clear scope for engagement so they could appropriately allocate their time was vital to delivering a Revenue Proposal that is capable of acceptance.

During the co-design workshop in May 2019, participants plotted elements that they considered had the largest impact on revenue against the ability for each element to be influenced by engagement. This enabled efficient and focused engagement. We updated our engagement scope in September 2020 to reflect new engagement elements on insurance and the Demand Management Innovation Allowance Mechanism (DMIAM). Figure 3.2 consolidates the input from the workshop and subsequent scope of engagement for our 2023-27 Revenue Proposal.

9 Customer Panel, Powerlink, https://www.powerlink.com.au/customer-panel.

Figure 3.2: Engagement scope



Using the inputs from the co-design workshop and customer feedback, aspects of the Revenue Proposal were plotted against the relevant level of the IAP2 Spectrum[10]. This spectrum is designed to assist with the selection of the level of participation that defines the public's role in any community engagement program.

In Table 3.3 we compare our original Engagement Plan, published in September 2019, against the topics which we have engaged on by January 2021. This demonstrates how we have adjusted our engagement focus based on the relevance of topics and customer and stakeholder interest throughout the development of our Revenue Proposal.

10 IAP2 Spectrum, International Association of Public Participation, 2018.

Table 3.3: Engagement scope against the IAP2 Spectrum

	Timing	
Level of IAP2 Spectrum	Engagement scope as per Engagement Plan September 2019	Engagement scope as at January 2021
Empower To place the final decision-making in the hands of customers and stakeholders	Nil	Decision on whether our Revenue Proposal is capable of acceptance[(1)].
Collaboration To partner with customers to formulate alternatives and incorporate their advice into final decisions to the maximum extent possible	Engagement approach. Contingent and Integrated System Plan (ISP) projects. Operating environment (Business Narrative).	Engagement approach. Operating environment (Business Narrative). Contingent projects (including contingent reinvestment concept). Depreciation tracking approach. Capable of acceptance criteria. Preliminary Positions and Forecasts Paper (PPFP) content.
Involve To work directly with customers and stakeholders to ensure their concerns and aspirations are directly reflected in the alternatives developed	Capital expenditure – augmentation expenditure, reinvestment expenditure, forecasting methodology. Operating expenditure – efficient base year, step changes. Service Target Performance Incentive Scheme (STPIS).	Insurance. Capital expenditure – forecasting methodology. Operating expenditure – efficient base year, step changes, productivity STPIS – potential review of scheme and relevant years for setting targets. Transmission Pricing Consultation/Proposed Pricing Methodology. Cyber security. Long-term revenue smoothing. Publication of a draft Revenue Proposal. Affordability – in the context of capital and operating expenditure forecasts.
Consult To obtain feedback on alternatives and draft proposals	Capital expenditure – key inputs and assumptions, Information Technology. Operating expenditure – forecasting methodology, trends (productivity). Price and revenue path. Pricing Methodology. Australian Energy Market Commission (AEMC) Levy. Depreciation.	ISP projects. Capital expenditure – augmentation expenditure, reinvestment expenditure, key inputs and assumptions, Information Technology. Inflation – impacts on revenue from different treatments of inflation. AER Benchmarking.
Inform To provide balanced information to keep customers and stakeholders informed	Rate of return. Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS). RAB. Shared assets. Pass throughs.	Operating expenditure – forecasting methodology. AEMC Levy. Powerlink risk appetite. Proposed rate of return. EBSS and CESS. RAB impacts. Shared assets. Pass throughs events. COVID-19 potential impacts.

(1) We recognise the IAP2 spectrum definition of empower is to implement what customers decide. This inclusion is not to be read that the Final Decision on our Revenue Proposal is in the hands of customers, rather to indicate our intent to empower and encourage customers to make their own decision on capable of acceptance, which should be taken into account by the AER and ourselves.

3.5 Engagement participants

While deep engagement occurred with a range of customers and stakeholders, we also put significant effort into providing engagement opportunities to a wider range of stakeholders across Queensland.

Gaining participation from a broader range of stakeholders is challenging for a transmission business due to our less visible position in the supply chain i.e. as opposed to distribution businesses, which have a more direct customer-facing role. We were also conscious of the value proposition of dedicating resources and budget toward wide-scale engagement against stakeholder interest and understanding of a revenue determination process.

The key stakeholders and customers with whom we directly engaged on a regular basis are outlined in Table 3.4.

Table 3.4: Regular engagement participants

Activity	Members
Customer Panel	Aurizon BHP Council on the Ageing (COTA) CS Energy Commonwealth Scientific and Industrial Research Organisation (CSIRO) Edify Energy Energy Consumers Australia (ECA) (up to August 2020) Energy Queensland Energy Users Association of Australia (EUAA) Queensland Farmers' Federation (QFF) Queensland Resources Council (QRC) Shell St Vincent de Paul Invitees: AER staff and AER CCP23
Revenue Proposal Reference Group (a sub-set of the Customer Panel)	CS Energy EUAA QFF Shell Energy Consumers Australia (up to June 2020) COTA (from July 2020) Invitees: AER staff and AER CCP23
Regulatory	AER staff and AER CCP23
Government	Queensland Treasury, Department of Energy and Public Works.

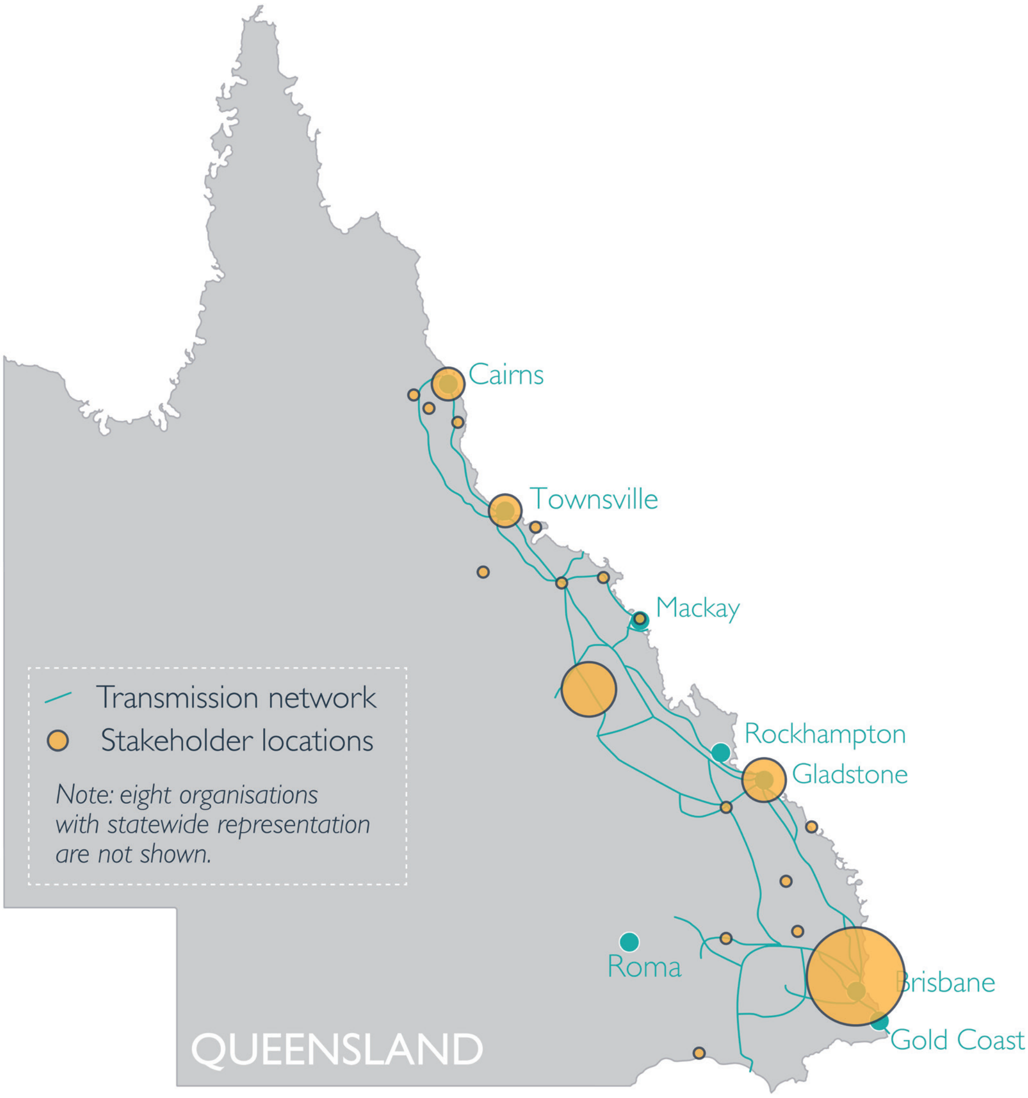
We also engaged with a wide range of customers and stakeholders, including across regional Queensland, to give further breadth to our engagement.

Key activities that we undertook to gain broader input and participation on our Revenue Proposal included:

- creating a master stakeholder list of more than 450 contacts to share key documents with, including our Preliminary Positions and Forecasts Paper (PPFP) and draft Revenue Proposal. These stakeholders were also invited to participate in Powerlink's Transmission Network Forum, webinars and other online forums;
- customers and stakeholders participated in our draft Revenue Proposal webinar (32 participants), Transmission Network Forum (more than 240 participants) and Insurance Deep Dive (15 participants);
- proactively contacting key regional advocacy and economic bodies to invite them to engagement opportunities;
- 20 one-on-one briefings with directly-connected customers who operate across Queensland on, for example, transmission pricing arrangements;
- the Revenue Proposal was included as part of broader briefings with more than 20 local governments (Mayors and CEOs), with more detailed briefings offered;
- to seek insights on key issues from landholders and local governments through a Stakeholder Perception Survey, undertaken independently by Deloitte on an annual basis;
- promotion of key information and engagement opportunities through our social media channels and website; and
- provision of information and promotion of engagement opportunities through the communication networks of key advocacy groups, for example QFF and EUAA.

Figure 3.3 provides a map which outlines the location or geographic areas represented by customers and stakeholders across Queensland that we engaged with in the development of our 2023-27 Revenue Proposal. As a guide, the larger the circle, the greater the number of stakeholders involved in engagement from that area.

Figure 3.3: Breadth of engagement map



3.6 Engagement activities

We based our engagement activities on feedback from customers and stakeholders at the Revenue Proposal co-design workshop in May 2019 and leveraged off existing business-as-usual engagement avenues as much as possible.

Insights from the workshop included:

- our business-as-usual Customer Panel should play a primary engagement role;
- publish early forecasts approximately six months in advance of the Revenue Proposal to provide greater visibility and opportunity for comment;
- undertake one-on-one briefings with directly-connected customers and target stakeholder groups;
- raise customer and stakeholder understanding of the transmission industry, including the regulatory environment;
- deep dives should focus on large, complex or contentious topics that have the greatest potential to impact MAR and for which the business has not yet made a decision;
- test interest in hosting engagement forums in regional locations;
- use webinars and Powerlink's website to make information easily accessible despite geographic location;

- establish a microsite or dedicated section on Powerlink's website to educate and facilitate interactive feedback and discussion; and
- investigate site tours to allow customers and stakeholders to learn about Powerlink's operations.

Key engagement activities undertaken in the development of our 2023-27 Revenue Proposal are summarised in Table 3.5.

Table 3.5: Key engagement activities

Activity	Description
Customer Panel meetings	The Customer Panel has played a key role in engagement on a range of important aspects in the development of our Revenue Proposal. Our goal was to gain agreement on these aspects from panel members to ensure the Revenue Proposal was capable of acceptance. The Customer Panel also held meetings in October 2020 and December 2020 without any Powerlink representatives. The first meeting was a discussion on the Panel's submission to our draft Revenue Proposal. The second evaluated our engagement approach and discussed capable of acceptance criteria and assessment.
RPRG meetings	The RPRG met every four to six weeks from October 2019 to December 2020 for detailed discussions on items identified in the engagement scope. Meetings were typically two to four hours in length and detailed information was provided prior to the majority of meetings, all of which has been made public on our website[1]. RPRG members then reported back to the wider Customer Panel on the focus areas and outcomes of those discussions. Specific topics discussed with the RPRG are outlined in the engagement timeline in Section 3.7.
Draft Revenue Proposal	In response to customer feedback, we published a draft Revenue Proposal on 30 September. This is discussed further in Section 3.2. A formal one month submission period allowed customers and stakeholders to provide feedback on our draft Revenue Proposal. We provided a template to guide customer input. Submissions received have been published on our website and included in Appendix 3.02 Submissions on our draft Revenue Proposal. Feedback has had a direct influence on our Revenue Proposal, in particular, in relation to our capital expenditure forecast and capable of acceptance criteria (refer Section 3.8).
Draft Revenue Proposal webinar	A webinar was held in October 2020 to allow customers and wider stakeholders to gain a better understanding and provide feedback on our draft Revenue Proposal. In total, 32 participants joined the webinar. A recording of the webinar and associated material was made available in full on our website. Customers heard from and were able to ask questions directly of our Chief Executive and other members of our Executive Team and staff during this session.
PPFP	In early August 2020, we released a Preliminary Positions and Forecasts Paper (PPFP) to provide customers and stakeholders with a more detailed update on our Revenue Proposal forecasts at that stage of development, and drivers of our capital and operating expenditure. This information was shared with more than 200 stakeholders and customers, and we encouraged feedback on the PPFP.
Transmission Network Forum	We hold our Transmission Network Forum in September each year with close to 200 attendees from across Government, industry, customer groups, regulators and consumer advocates. In 2019, a dedicated exhibition at the forum shared our early thinking and sought views on our capital expenditure approach and proposed engagement activities. In 2020, due to COVID-19, the forum was held virtually with more than 240 attendees. A dedicated presentation outlined key drivers of our Revenue Proposal. We invited a wider range of customers and stakeholders, particularly regional representatives, to be involved in engagement post the release of the draft Revenue Proposal and provide submissions on the document.
Insurance deep dive	We held a deep dive session in November 2020 on our approach to managing risk and cost trade-offs associated with insurance. This deep dive concentrated on the challenge of managing potential increases to our insurance premiums in the 2023-27 regulatory period, which is discussed further in Chapter 6 Forecast Operating Expenditure. Customers were able to hear from and ask questions of our Chief Financial Officer, who is responsible for our insurance program, and provide their views on appropriate levels of risk and cost trade-offs related to insurance. A summary of this session is published on our website[2]. While we did not specifically refer to them as deep dives, we consider that engagement with our RPRG and Customer Panel to be deep across a range of topics as part of each meeting. These topics are summarised in Section 3.8.

Activity	Description
One-on-one briefings	All directly-connected customers were offered a one-on-one briefing. Twenty briefings occurred either as part of our consultation with directly-connected customers on transmission pricing or specifically on elements of our Revenue Proposal.
Regional engagement	It was important to provide regional stakeholders with an opportunity to participate in our engagement process. Our master stakeholder list of more than 450 contacts included regional representatives who were sent relevant information and invited to participate in engagement activities. Key regional representatives were contacted to encourage participation in major engagement activities. Approximately 60 attendees at our 2020 Transmission Network Forum represented regional areas. We have also hosted targeted online forums to allow a range of stakeholders from across Queensland to ask questions and provide input. We provided high level briefings to 20 local governments across Queensland including Cairns, Isaac, Mackay and North Burnett.
Digital engagement	We established a dedicated section on our website as a central point of information on our Revenue Proposal for customers and stakeholders. It has also provided a digital platform for interactive feedback. Interested parties were able to subscribe to this page to receive notification of information updates. All Customer Panel and RPRG presentations, pre-reading and meeting minutes and webinar recordings are publicly available on our website.
Formal research	We sought customer and stakeholder insights through formal research, namely a dedicated annual Stakeholder Perception Survey undertaken independently by Deloitte which involved 115 stakeholders and customers in 2020. Our 2020 survey results show ongoing support for our broader engagement approach and social licence to operate. The survey also asked specific questions about engagement on our Revenue Proposal, which contributed toward our evaluation outcomes discussed in Section 3.9. Each year Powerlink also partners with Energy Queensland on the Queensland Household Energy Survey. This survey captures the views of more than 5,000 Queensland households on areas including energy consumption patterns, uptake of solar and new technologies and sentiment towards energy companies. We use this information to inform our network planning.
Informal discussions and feedback	Throughout the process we sought regular informal feedback and responded to questions and emails from customers, stakeholders, the AER and the AER's CCP23. We responded to queries and coordinated responses and discussions with groups of interested customers and stakeholders where relevant.

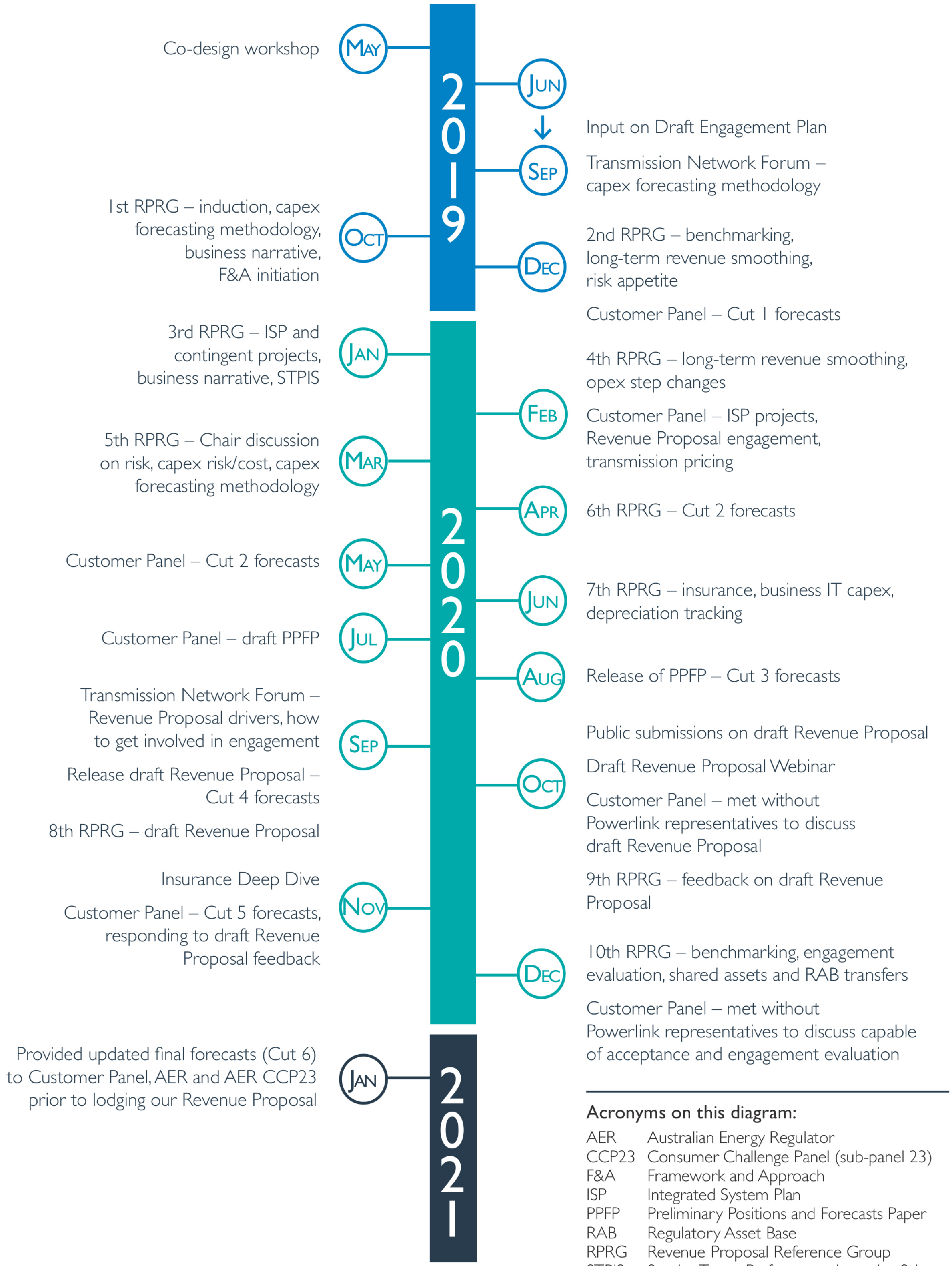
(1) 2023-2027 Regulatory Period, Powerlink, https://www.powerlink.com.au/2023-27-regulatory-period.

(2) Insurance Deep Dive Overview, 13 November 2020, Powerlink, http://www.powerlink.com.au/2023-27-regulatory-period.

3.7 Engagement timeline

Engagement on our Revenue Proposal started in May 2019 with the co-design workshop. Figure 3.4 provides an overview of key engagement activities and discussion topics.

Figure 3.4: Engagement timeline



Acronyms on this diagram:

AER	Australian Energy Regulator
CCP23	Consumer Challenge Panel (sub-panel 23)
F&A	Framework and Approach
ISP	Integrated System Plan
PPFP	Preliminary Positions and Forecasts Paper
RAB	Regulatory Asset Base
RPRG	Revenue Proposal Reference Group
STPIS	Service Target Performance Incentive Scheme

3.8 How feedback influenced our decision-making

We genuinely considered all input and feedback from customers and stakeholders. The key topics discussed, feedback received and how that feedback influenced our decision-making is summarised in Table 3.6.

Information has been grouped by the following topics:

- general and engagement;
- capital expenditure;
- operating expenditure;
- financials;
- STPIS; and
- transmission pricing.

The date provided reflects key times when topics were discussed in detail with the RPRG or Customer Panel. It is not intended to reflect every time these topics were discussed. Topics are presented in reverse chronological order (i.e. most recent topics discussed are first).

Table 3.6: How feedback influenced decision-making

Topic	Feedback received	What we've done
General topics and engagement		
Capable of acceptance goal (December 2020 and September 2020)	• Customers suggested adopting the criteria proposed by CCP24 in the context of Australian Gas Networks (AGN) 2020 Access Arrangement in June 2020 to assess whether capable of acceptance has been met. • The AER and CCP23 also suggested considering the AER's Framework for Considering Consumer Engagement, published in September 2020, as the criteria for capable of acceptance[1].	• We originally proposed using the CCP24 criteria in our draft Revenue Proposal. • The Framework for Considering Consumer Engagement was released after the CCP24 criteria and we consider it constructively built on the original criteria suggested by CCP24. • We adopted the criteria in the Framework for Considering Consumer Engagement and provide a self-assessment against this criteria in Section 3.2.
Draft Revenue Proposal (June 2020)	• Customers strongly encouraged us to publish a draft Revenue Proposal by September 2020.	• We published a draft of our Revenue Proposal in September 2020. This was not in our original plans given we had planned to release at least three sets of forecasts publically as our Revenue Proposal was being developed (refer Section 3.2).
COVID-19 impacts (May 2020 and April 2020)	• Customers asked about the impacts of COVID-19 on our Revenue Proposal. • Customers supported maintaining the existing timeline for lodgement of our Revenue Proposal. • We received feedback that RPRG and Customer Panel meetings should be shortened and be more targeted, if possible. • Customers asked how we are planning to continue engagement given the impacts of COVID-19.	• We maintained our existing timeline for the preparation and lodgement of our Revenue Proposal. • We held virtual meetings to adjust to the impacts of COVID-19. These meetings were shortened and more targeted. • We have provided clarity about the impact of COVID-19 on our capital and operating expenditure in our draft Revenue Proposal and in our Revenue Proposal.
Risk appetite (March 2020)	• Customers asked for insight into the risk appetite and approach of our Board.	• Our Board Chair, Kathy Hirschfeld, outlined and answered questions on our risk profile, risk management policies and controls at the March 2020 RPRG meeting.
Business Narrative (December 2019 and October 2019)	• First draft did not reference impacts of climate change. • Need to clarify the target audience for the narrative. • Explain how factors will impact Revenue Proposal and customers. • Customer section needs to focus on more than just affordability. It should also focus on how customers will be empowered in their energy use as part of the transition.	• Several versions of our Business Narrative were circulated to the RPRG and Customer Panel with feedback incorporated into the updated Business Narrative (e.g. more explicit discussion of risks, the environment and defining the document's intended target audience).

Topic	Feedback received	What we've done
Capital expenditure		
Affordability and our overall capital expenditure forecast (December 2020, November 2020)	• In response to our draft Revenue Proposal, customers were concerned about the proposed 12% increase in capital expenditure from the current regulatory period and its impact on customer affordability.	• Since our draft Revenue Proposal, we have continued to focus on how we can more prudently and efficiently manage the network while continuing to deliver safe, secure, reliable and cost-effective electricity transmission services. • We have reduced our total forecast capital expenditure and proposed a 3% real reduction in capital expenditure from the current regulatory period (refer Chapter 5 Forecast Capital Expenditure).
Contingent reinvestment projects (December 2020, January 2020)	• There was initial support from customers for the concept of contingent reinvestment projects for those investments that may have significant uncertainty around need, timing and cost. • While the RPRG and the AER's CCP23 were supportive of the concept as a way to balance risks between consumers and Powerlink, their feedback on our draft Revenue Proposal was to not support using the existing contingent project framework. • The AER raised concerns with regards to asset condition triggers and the potential for contingent reinvestments to move away from an incentive-based to more of a cost-of-service regulatory approach.	• We decided not to pursue contingent reinvestment projects in our Revenue Proposal (refer Chapter 5 Forecast Capital Expenditure). • We still consider that this concept has merit and may pursue this outside the Revenue Proposal process.
Hybrid+ capital expenditure forecasting methodology and scenario analysis (October 2020, October 2019)	• Customers recognised the challenges of pursuing a full bottom-up forecast and the reasons for our Hybrid+ approach. • There was broad support for our Hybrid+ approach as striking a reasonable balance between bottom-up and top-down forecasts at our October 2019 RPRG meeting. • Our Customer Panel and the AER's CCP23 were interested in understanding the amount of top-down and bottom-up analysis undertaken and the extent to which scenario analysis has contributed to our forecasts.	• We adopted the Hybrid+ model to forecast capital expenditure. • We have provided further information in Chapter 5 Forecast Capital Expenditure on the extent of our top-down and bottom-up analysis. • Scenario analysis has not been undertaken specifically for our Revenue Proposal. However, it contributes to the development of business-as-usual documents such as our Transmission Annual Planning Report (TAPR) and Asset Management Plans, which are provided as supporting documents to our Revenue Proposal.
Business Information Technology (IT) (June 2020)	• Customers had direct input into the development of our new IT Benefits Realisation Framework. Feedback focused on the criteria and metrics to support IT investment. • Based on the forecast capital expenditure provided, the RPRG and Customer Panel did not request deeper engagement on Business IT. • AER requested additional IT investment cases to be provided.	• We presented our final IT Benefits Realisation Framework to the Customer Panel in February 2020, which incorporated their feedback. • We published a draft business IT investment case with our draft Revenue Proposal in September 2020. • Seven IT investment cases are provided as part of our Revenue Proposal. • We considered sharing a business IT post-implementation review prior to Revenue Proposal lodgement, noting the Benefits Realisation Framework is newly developed. However, this was not achievable in the timeframe and we will consider this for discussion post-lodgement.

Topic	Feedback received	What we've done
Replacement expenditure (Repex) model (March 2020)	• Customers and AER staff wanted to ensure the Repex Model did not double-count expenditure included within bottom-up forecasts. • Customers asked us to provide additional evidence on age profiles of transmission towers (including by corrosion zone) and historical trend information on tower reinvestments.	• We reviewed inputs into the Repex Model and our approach to integrating the top-down and bottom-up elements. This verified that our approach will not result in expenditure being double-counted. • Transmission tower age profiles and historical trend information has been published with the Repex Model and associated input data files.
Integrated System Plan (ISP) projects (various dates)	• Customers are interested in how the Queensland/New South Wales Interconnector (QNI) Medium project and associated easement acquisition will be treated in the Revenue Proposal. • Of particular interest is how cost estimates for ISP projects were developed for the 2020 ISP.	• We had discussions with interested customers on the costs associated with the QNI Medium project. • We have proposed $14.3m to acquire new easements required for the QNI Medium upgrade (refer Chapter 5 Forecast Capital Expenditure).
Operating expenditure		
Affordability and our overall operating expenditure forecast (various dates)	• Customers stated that affordability was a key issue and encouraged us to take proactive steps in our operating expenditure forecast to address affordability. • Our Customer Panel and the AER's CCP23 welcomed our no real growth in operating expenditure forecast in their draft Revenue Proposal response.	• We have heard customer feedback on business productivity, affordability and the impacts of the current economic climate. Based on this feedback we have committed to pursue a target of no real growth in operating expenditure. • We have set a 0.5% productivity target, which is above the industry average, and proposed no step changes. The combination of real productivity growth above the industry average and no proposed step changes reflects our commitment to customers to target no real growth in operating expenditure.
Benchmarking (December 2020, December 2019)	• Customers want to see us make genuine improvements in capital and operating expenditure rather than just target improvements to look good on 'the beauty parade'. • Customers acknowledged that changes to certain inputs can have a material impact on benchmarking results without improving outcomes for customers(2). • Customers wanted to see operating expenditure performance against key metrics.	• We focused on pursuing changes that provide genuine benefits to customers and not changes that may improve benchmarking but with no real customer benefit. This was outlined in our February 2020 RPRG meeting. • We provided feedback to AER staff on the benchmarking model, in particular that our 2019 zero unserved energy result may materially impact the function of the benchmarking model and our overall result. • We have included operating expenditure performance against key metrics in Chapter 6 Forecast Operating Expenditure.
Productivity (October 2020, December 2019)	• Customers encouraged us to drive a higher operating expenditure productivity target than the industry trend. • Customers sought further detail on planned productivity initiatives. • Customers asked if we could develop a forecast of our productivity performance for the 2023-27 regulatory period.	• Based on customer feedback and recognition of the current economic environment, we have adopted a customer-focused strategy to pursue a target of no real growth in total operating expenditure. • As a result, we have proposed a productivity factor of 0.5% per annum in combination with no step changes (refer Chapter 6 Forecast Operating Expenditure). • Appendix 6.02 Operating Expenditure Productivity Approach and Potential Initiatives provides further information on initiatives that may be implemented to improve our productivity. • We have provided metrics of our operating expenditure and a forecast of our operating expenditure partial factor productivity in Chapter 6 Forecast Operating Expenditure.

Topic	Feedback received	What we've done
Base year (November 2020, October 2020)	• Customer feedback was the choice of 2018/19 as the base year appeared reasonable. There was a query as to whether using a base year closer to 2022/23 would be considered. • Customers requested a copy of the HoustonKemp report into the efficiency of Powerlink's base year prior to the Revenue Proposal being lodged.	• We retained 2018/19 as our base year as it is reflective of a typical year of operations (i.e. without the potential uncertainties and inconsistencies in expenditure associated with COVID-19 (refer Chapter 6 Forecast Operating Expenditure). • Our Customer Panel, the AER and the AER's CCP23 were provided an advance copy of HoustonKemp's report on 1 December 2020.
Insurance (November 2020, June 2020)	• Customers recognise and are concerned by increases in insurance premiums across the energy sector. • Customers want to understand the drivers of the increase in insurance premiums and what steps can be taken to manage risk and costs. • Customers requested further information on how we will manage the balance between premiums, self-insurance and cost pass throughs. • At our insurance deep dive session, customers asked us to determine if cost savings could be generated by gaining different levels of insurance cover for network assets based on their geographic location. Due to the fluid nature of insurance, customers asked for greater visibility of the yearly renewal process.	• We arranged for our insurance brokers, Marsh, to provide an overview of the hardening insurance market and drivers for this (e.g. increasing volume of claims due to economic downturn and natural disasters). • We decided to change our forecasting approach to insurance and have included it in our base year due to the uncertainty in the market (refer Chapter 6 Forecast Operating Expenditure). • We will continue to review our insurance coverage and consider the trade-offs between costs and risks to seek a reasonable balance for customers and Powerlink. • We committed to engaging with our Customer Panel within period to discuss material changes in insurance costs and any pass through applications prior to lodgement with the AER, if any.
Step changes (February 2020)	• Customers were interested in how potential step changes were identified and which ones would not be pursued. • Customers asked what the legislative/ regulatory drivers were and how can we engage with regulators and government to reduce cost impacts. • Customers asked how they could assist with the engagement with government. • Customers asked whether the operating expenditure forecast includes the AEMO National Transmission Planner (NTP) Fee.	• We initially identified 27 potential step changes. • After further engagement and consideration, we decided not to proceed with any step changes in combination with a revised productivity forecast to achieve our target of no real growth in operating expenditure (refer Chapter 6 Forecast Operating Expenditure and Appendix 6.03 Operating Expenditure Step Changes Approach). We will endeavour to manage and absorb potential costs associated with step changes as part of our forecast operating expenditure for the 2023-27 regulatory period. • A key reason for this was to reduce the impact on operating expenditure to drive customer affordability in the current economic environment. • Consistent with the Rules[3], AEMO NTP fees are applied outside the revenue determination process (refer Chapter 6 Forecast Operating Expenditure).
Cyber security (February 2020)	• Customers want to understand the costs of our cyber security program (capital and operating expenditure) and our intended approach.	• We include information in Chapter 5 Forecast Capital Expenditure and Chapter 6 Forecast Operating Expenditure on cyber security. • Consistent with our target of no real growth in operating expenditure and due to the uncertainty associated with costs and obligations, we decided not to pursue an operating expenditure step change for cyber security.

Topic	Feedback received	What we've done
Financials		
Inflation (November 2020, July 2020)	• Customers sought clarification on how different treatments of inflation can impact revenue (e.g. the difference between trimmed mean and headline inflation). • Customers requested an indication of the impact of the change in inflation approach proposed as part of the AER's Inflation Review[4].	• We intend to publish an overview document on our website to explain how inflation is captured and how it can impact revenue under the regulatory framework. • We have included a forecast of the impact of the new inflation approach in Chapter 9 Rate of Return, Taxation and Inflation.
AER feedback on Revenue Proposal models (September 2020, July 2020)	• We provided the AER with early versions of our key Revenue Proposal models (e.g. Post-Tax Revenue Model (PTRM), Roll Forward Model (RFM), EBSS, CESS, Operating expenditure, Capital expenditure and Repex models) and the AER provided useful input to guide our use of the models.	• We made adjustments to the models where required and clarified points on each of these to ensure they are capable of acceptance.
Year-by-year depreciation tracking approach (June 2020)	• Customers acknowledged the change to the year-by-year depreciation tracking approach is more accurate over time. • We were asked to investigate whether the transitional impacts of this change in approach (i.e. higher revenue) could be mitigated/ smoothed. • Customers asked whether the Queensland Audit Office (QAO) supported this approach.	• We investigated options to smooth the transitional impact and have proposed to manage this by a minor change to asset lives for existing secondary systems assets at 30 June 2017. This smooths the revenue impact on customers between the 2023-27 and 2028-32 regulatory periods. We have adopted this approach (refer Chapter 10 Depreciation). • Depreciation tracking is a forecasting approach in the regulatory framework. It does not require QAO sign off, therefore we have not sought their input on the approach.
Proposed revenue smoothing (February 2020, December 2019)	• Customers raised concerns that after the 2023-27 regulatory period, prices could materially increase if our rate of return increased. • Customers provided initial support for us to undertake further analysis to gain a better understanding of alternative ways to potentially smooth the impact of subsequent rate of return increases on prices.	• We decided not to progress this due to challenges in relation to potential changes that may be required to the Rules, regulatory risks and overall minimal customer benefits that were forecast to result. • RPRG members supported our position. The RPRG acknowledged our efforts to explore a 'new way of doing things' but agreed that the associated complexities were not likely to result in material benefits for customers.
Service Target Performance Incentive Scheme (STPIS)		
STPIS review (January 2020)	• Customers supported our proposal for the AER to review the STPIS[6]. • Customers were keen to ensure that the STPIS appropriately incentivised improvements in network performance to benefit market participants and customers. • As part of feedback on the draft Revenue Proposal, customers deferred to the AER in relation to a decision on STPIS. The AER's CCP23 indicated they did not feel there was a reason to change the STPIS.	• We coordinated input from all other Transmission Network Service Providers (TNSPs) on the operation and a potential review of the current STPIS scheme. • We lodged a request and supporting information with the AER in January 2020 to review the STPIS. • The AER notified Powerlink in August 2020 that it does not consider that a review of STPIS is necessary at this time. • We remain firmly of the view that the STPIS should be reviewed in light of the significant and rapid changes in the energy market, to ensure it remains fit-for-purpose and continues to promote the long-term interests of consumers (refer Chapter 15 Service Target Performance Incentive Scheme).

Topic	Feedback received	What we've done
Transmission Pricing		
Transmission Pricing (various dates)	• Broadly, customers supported providing stronger pricing signals to encourage more efficient use of the network, driving lower future network costs. • Detailed feedback on other aspects of our Transmission Pricing Consultation is provided in Chapter 16 Pricing Methodology.	• As a result of our Transmission Pricing Consultation we proposed one amendment to our existing Pricing Methodology. The proposal is to progressively move to locational charges being based on peak demand only. • Our response to customer feedback is detailed further in Chapter 16 Pricing Methodology.

(1) Overview, Section 3, Table 7 in the Draft Decisions for AusNet Services, Jemena, United Energy, CitiPower and Powercor, Australian Energy Regulator, September 2020.

(2) Minutes of the Revenue Proposal Reference Group (RPRG), Powerlink, December 2019, https://www.powerlink.com.au/2023-27-regulatory-period.

(3) National Electricity Rules, clause 6A.23.3(e)(6).

(4) Regulatory Treatment of Inflation, Australian Energy Regulator, December 2020.

(5) Minutes of the RPRG January 2020 meeting, Powerlink, https://www.powerlink.com.au/2023-27-regulatory-period.

3.9 Engagement evaluation

We gained qualitative and quantitative data on our engagement approach. This was done through a range of mechanisms including a survey of Customer Panel members, a dedicated session on engagement evaluation with the RPRG and a Customer Panel meeting without Powerlink representatives present to allow panel members to evaluate our engagement. We also provided opportunities for customers and stakeholders to give feedback before, during and after participation in key engagement activities.

Throughout the development of our Revenue Proposal we regularly asked participants for input and feedback on the effectiveness of engagement to ensure alignment with their expectations.

3.9.1 Quantitative engagement evaluation

Our Engagement Plan, included in Appendix 3.01, provides a set of Key Performance Indicators (KPIs). We engaged with our customers on these prior to their finalisation. The KPIs, our method of evaluation and evaluation outcomes are outlined in Table 3.7.

Table 3.7: Evaluation KPIs and outcomes

KPI	Target	Measurement techniques used	Evaluation outcome
Effectiveness and quality of information provided to stakeholders	Overall satisfaction rating of 7/10 for quality of information provided.	• Pulse check surveys. • Informal debriefs.	• Customer Panel members rated quality of information at 8.5/10 (refer to Appendix 3.05 Customer Panel Evaluation Survey)(1). • Informal feedback during RPRG and Customer Panel meetings indicated the information provided for meetings was appropriately detailed to enable meaningful engagement.
Stakeholders were engaged at appropriate level on the IAP2 spectrum	Identified that majority of stakeholders had appropriate level of influence on Powerlink decision-making.	• Survey/solicit feedback from external stakeholders. • Internal review. • Peer review/audit.	• Customer Panel members rated their ability to influence decision-making at 7.5/10 (refer to Appendix 3.05 Customer Panel Evaluation Survey).

KPI	Target	Measurement techniques used	Evaluation outcome
Satisfaction level of stakeholders with engagement activities	An overall satisfaction rating of 7/10 for engagement activities.	• Formal research. • Post-activity satisfaction surveys. • Informal debriefs and feedback.	• 70% of participants (wider than Customer Panel members) were either satisfied or very satisfied with the engagement approach (refer to Appendix 3.06 2020 Stakeholder Perception Survey Summary). • Customer Panel members rated the effectiveness of engagement at 8.26/10 (refer to Appendix 3.05 Customer Panel Evaluation Survey). • Participants at the 2020 Transmission Network Forum gave an overall satisfaction rating of 83% for the event (refer to Appendix 3.07 Transmission Network Forum Participant Feedback Summary 2020). • The Customer Panel Statement on Engagement (refer to Appendix 3.03) indicated our engagement approach has been genuine, consistent and deep.
Impact of engagement on Powerlink decision-making and quality of feedback/ input received	Ability to demonstrate what changed as a result of engagement.	• Survey/solicit feedback from external stakeholders. • Internal review. • Peer review/audit.	• Significant elements of Powerlink's Revenue Proposal were changed directly as a result of customer feedback (refer to Table 3.6). • The Customer Panel Statement on Engagement (refer to Appendix 3.03) identified a number of cases where their input had influenced our Revenue Proposal. Panel members described the level of influence as high relative to other engagement processes in the industry.
Timely delivery of engagement program	Engagement program delivered on-schedule.	• Internal monitoring.	• Key engagement milestones were delivered on schedule. In addition, we published a draft Revenue Proposal which was unplanned, in response to feedback from customers (refer Section 3.2).
Improvement in social licence to operate score and reputation scores	Improvement on 2018 social licence to operate and reputation scores, and positive verbatim feedback regarding revenue determination process engagement.	• Formal research via the Deloitte Stakeholder Perception Survey.	• Positive feedback received on our engagement approach by Customer Panel and AER CCP23[(2)]. • Our social licence to operate score has improved in both 2019 (4.01) and 2020 (4.03) and our reputation remained high in both 2019 (4.03) and 2020 (3.78) (refer to Appendix 3.06 2020 Stakeholder Perception Survey Summary). These are measures of reputation and social licence to operate beyond just our Revenue Proposal engagement process.

(1) Note this survey was done on a 1-5 scale and results have been calculated on a 1-10 basis.

(2) Appendix 3.02 Submissions on our draft Revenue Proposal and Appendix 3.03 Customer Panel Statement on Engagement.

3.9.2 Qualitative engagement evaluation

We have relied on four main sources of qualitative feedback to inform our Revenue Proposal and evaluate the effectiveness of our engagement approach. These are:

- our Customer Panel's Statement on Engagement (Appendix 3.03) from December 2020;
- feedback from our RPRG at the December 2020 meeting;
- our Customer Panel's submission on our draft Revenue Proposal (Appendix 3.02); and
- the AER CCP23's submission on our draft Revenue Proposal (Appendix 3.02) and feedback at the December 2020 RPRG meeting.

We have not sought to replicate all qualitative feedback received via the sources above in our Revenue Proposal. We have included in Table 3.8 some verbatim key statements from both the Customer Panel and AER CCP23 that support our engagement approach and discussed areas for improvement in Section 3.9.3.

Table 3.8 Qualitative statements on our engagement approach

Source	Statements
Customer Panel Statement on Engagement	The panel are unanimous in our view that the Powerlink's engagement with us has been genuine, consistent and deep. We also acknowledge the consistent high-level efforts of Powerlink staff to ensure that they engage meaningfully with us. Their [the Customer Panel's] level of influence was higher relative to other engagement processes in the industry.
RPRG comments from the December 2020 meeting	The engagement has been genuine, transparent and quite focused. I think we could certainly classify the engagement with the RPRG as deep engagement. I think that we can point to examples where views that have been expressed by RPRG members and Customer Panel members have strongly influenced the proposal. I want to comment on how successful your original intentions were around the co-design process and how we sort of went bravely into this process we've used and I think it's been a success. You seek to have engagement to help understanding and to inform and to increase transparency. The deep dives have been terrific. I really do feel it's been genuine. That it's been open and very authentic.
Customer Panel submission to our draft Revenue Proposal	Powerlink's engagement to date has been genuine and open. We have been afforded regular opportunities to provide feedback on the plans as they have progressed through several iterations, and our views have been recorded and taken into account.
AER CCP23 submission to our draft Revenue Proposal and feedback at the December 2020 RPRG meeting	We consider that Powerlink's engagement approach to date has been appropriate and has provided high-quality input for Powerlink's consideration. The iterative approach applied by Powerlink means that engagement influence has been observable over time and culminating, at this stage in the draft Revenue Proposal. With engagement across the board with networks, the bar is getting higher and higher. Powerlink is at the forefront of raising the bar on consumer engagement. Powerlink is right up there with how you build trust. Well done.

3.9.3 Continuous improvement on engagement

We take a continuous improvement approach to our engagement activities. While our engagement on the Revenue Proposal overall has generally been well received by customers and stakeholders, feedback has also identified areas where we could improve, which we welcome.

These improvement areas are also primarily derived from the same four sources of qualitative feedback noted in Section 3.9.2 and grouped in the following topics:

- breadth of engagement – provide more evidence of engagement with wider customers and stakeholders, engage more broadly across Queensland and demonstrate how engagement with those outside the Customer Panel has influenced decision-making;
- investigate greater diversity and succession planning for the Customer Panel;
- provide more face-to-face engagement opportunities for regional stakeholders; and
- share wider information from across the industry to provide greater context for engagement activities.

To continue to deliver for customers and stakeholders, we commit to reviewing our engagement approach with consideration to the above feedback to ensure it aligns with customer expectations.

3.10 Summary

This chapter outlines Powerlink's customer engagement activities and how they influenced and improved decision-making in the preparation of our 2023-27 Revenue Proposal. It highlights that we have undertaken extensive engagement with our customers, stakeholders, the AER's Consumer Challenge Panel (CCP23) and AER staff on all key elements of our Revenue Proposal.

This engagement occurred as part of our overarching goal to deliver a Revenue Proposal that is capable of acceptance by our customers, the AER and ourselves. The input we received from our engagement activities has directly shaped our Revenue Proposal.

4. Historical Capital and Operating Expenditure

4.1 Introduction

This chapter provides an overview of Powerlink's performance against the Australian Energy Regulator's (AER's) allowances for capital and operating expenditure during the current and preceding regulatory periods and provides context for forecast expenditure in the 2023-27 regulatory period. Our cost performance under the AER's Annual Benchmarking Report is also discussed.

Key highlights

- Our forecast outcome for the current 2018-22 regulatory period is:
  - total capital expenditure of $891.3m. This is $1.8m (0.2%) lower than the AER's allowance of $893.1m; and
  - total operating expenditure of $1,035.6m. This is $9.5m (0.9%) higher than the AER's allowance of $1,026.1m. These figures are exclusive of debt raising costs.
- Our performance under the AER's economic benchmarking approach has improved over the course of the current regulatory period. This is primarily attributable to a 7% real reduction in operating expenditure compared to the previous regulatory period, and a reduction in events that result in loss of supply to our customers (refer Chapter 15 Service Target Performance Incentive Scheme).

4.2 Regulatory requirements

The National Electricity Rules (the Rules)[1] require that our Revenue Proposal provides information related to our actual/forecast operating and capital expenditure over the current and preceding regulatory periods. The Rules[2] also require that, when considering our proposed forecast expenditure, the AER also has regard to such expenditure.

4.3 Powerlink's efficiency focus

A key focus area for Powerlink in the 2018-22 regulatory period has been to deliver better value to our customers through increased efficiency while continuing to deliver our services. Our cost performance in both capital and operating expenditure has improved from the 2013-17 regulatory period, driven by several key factors:

- the realisation of efficiency benefits from a reduction in layers within the organisational structure;
- review and adjustment of resource levels within the business in response to reduced demand and related capital expenditure forecasts. Full-time equivalent employee numbers reduced by approximately 14% between 30 June 2015[3] and 30 June 2020[4]; and
- review and implementation of a cost-effective long-term arrangement for maintenance service delivery. We determined that Ergon Energy has the requisite knowledge and skills to undertake these activities and has skilled resources in the same geographic areas as our assets[5]. On 12 May 2020 the AER granted a ring-fencing waiver to permit Ergon Energy to provide field services to Powerlink directly until 30 June 2025[6]. The AER concluded that, in this instance, the potential costs associated with compliance with the Distribution Ring-Fencing Guidelines are not warranted. This is expected to deliver efficiency savings across both capital and operating expenditure.

While cost control will remain a focus for Powerlink in the 2023-27 regulatory period we will seek to leverage innovation to help us increase productivity and improve customer outcomes. In particular, our target of no real growth in operating expenditure over the 2023-27 regulatory period will require us to find new and innovative ways to meet emerging challenges without necessarily increasing costs.

Our asset management planning approach focuses on how the required levels of transmission network service can be appropriately met, regardless of the type of assets deployed. Under this approach, potential asset reinvestment decisions do not consider solely like-for-like replacement. We consider if assets can be retired without replacement, whether other assets can be reconfigured, or non-network alternatives procured, to meet the network need.

1 National Electricity Rules, schedule 6A.1, clauses S6A.1.1(6) and S6A.1.2(7).
2 National Electricity Rules, clauses 6A.6.7(e)(5) and 6A.6.6(e)(5).
3 Annual Report 2014/15, Powerlink Queensland, 2015.
4 Annual Report 2019/20, Powerlink Queensland, 2020.
5 Outside of southern Queensland.
6 Final Decision Ergon Energy Ring-Fencing Waiver, Australian Energy Regulator, May 2020.

This holistic approach to network asset management has contributed to a reduction in our Regulatory Asset Base (RAB) during the current regulatory period in both nominal and real terms[7], and will contribute to a reduction in both nominal and real terms in the 2023-27 regulatory period[8] (refer Chapter 8 Regulatory Asset Base). A decline in our RAB provides ongoing savings to customers.

We have adopted a structured Innovation Framework to guide the creation and trial of new innovative practices to assess their suitability for broader adoption across the business. Key initiatives that are currently under trial or development include:

- New helicopter work practices to improve productivity in insulator replacement works. In more remote parts of the network this has reduced the per unit cost of insulator replacements by up to 30%.
- Procurement of a mobile switching bay to facilitate outages in constrained parts of the network. With the rapid changes being experienced on the power system, there are diminished opportunities for extended outages of switching bays to facilitate equipment refurbishment or replacement. The deployment of a mobile switching bay will provide a temporary bypass within a switching bay to allow the network element to remain in service while the main switching bay equipment is replaced.
- The use of drones and artificial intelligence to provide increased throughput, accuracy and consistency of the assessment of corrosion levels on steel transmission towers. This work is still in its early stages.
- We are investigating the application of Phasor Monitoring Units (PMUs) to improve our ability to monitor and respond to the changing characteristics of the power system as more Inverter-Based Resources (IBR) connect to the network. PMUs can provide high-speed and time-synchronised measurement of voltage and current phasors that can be used in real-time for both monitoring and control applications. This capability is expected to give us greater flexibility to manage outages that impact system strength and help maximise the network capability to host IBR.

4.4 Historical capital expenditure

Consistent with the requirements of the Rules[9], this section summarises our historical capital expenditure for the 2013-17 and 2018-22 regulatory periods.

Expenditure for the 2012/13 to 2019/20 financial years are actuals while the 2020/21 and 2021/22 financial years are based on our current expenditure plans and forecasts. All expenditure has been converted to real 2021/22 dollars using actual Consumer Price Index (CPI) outcomes published by the Australian Bureau of Statistics (ABS) and the most recent inflation forecasts published by the Reserve Bank of Australia (RBA).

We have also converted the expenditure allowance in the previous AER Final Decision[10] from real 2016/17 to real 2021/22 dollars using the same approach. This has resulted in actual expenditures and expenditure allowances reducing slightly from those published in our draft Revenue Proposal in September 2020.

4.4.1 Historical capital expenditure summary

Table 4.1 shows our actual/forecast capital expenditure for the previous and current regulatory periods by expenditure category.

7 Based on a comparison of 1 July 2017 opening RAB to 30 June 2022 closing RAB.
8 Based on a comparison of 1 July 2022 opening RAB to 30 June 2027 closing RAB.
9 National Electricity Rules, schedule 6A.1, clause S6A1.1(6).
10 Final Decision Powerlink transmission determination 2017-22, Australian Energy Regulator, April 2017.

Table 4.1: Capital expenditure – actual/forecast ($m real, 2021/22)[1]

	2013-17 regulatory period						2018-22 regulatory period					
	2012/13	2013/14	2014/15	2015/16	2016/17	Total	2017/18	2018/19	2019/20	2020/21 (forecast)	2021/22 (forecast)	Total
Network capital expenditure												
Augmentations	182.1	112.7	(1.4)	0.8	0.3	**294.4**	1.3	5.6	3.9	6.1	4.3	**21.3**
Connections	6.8	8.6	1.0	(1.3)	0.1	**15.1**	-	0.1	-	-	-	**0.1**
Easements	14.8	12.4	7.0	3.1	9.2	**46.5**	(0.2)	0.8	2.0	2.5	0.3	**5.4**
Total: load-driven	**203.7**	**133.6**	**6.5**	**2.5**	**9.6**	**355.9**	**1.2**	**6.5**	**5.9**	**8.6**	**4.6**	**26.8**
Reinvestments	267.8	203.6	145.0	107.0	109.6	**833.1**	120.8	144.7	136.2	139.5	172.0	**713.1**
System Services[2]	-	-	-	-	-	**-**	-	-	-	3.5	14.5	**18.0**
Security/ compliance[3]	6.0	6.6	5.1	3.1	29.6	**50.4**	20.6	2.2	1.3	1.0	0.0	**25.0**
Other	14.3	7.0	2.4	2.1	2.8	**28.5**	(0.3)	1.0	3.3	3.4	-	**7.4**
Total: non load-driven	**288.0**	**217.3**	**152.4**	**112.2**	**142.0**	**912.0**	**141.1**	**147.8**	**140.8**	**147.4**	**186.5**	**763.6**
Non-network capital expenditure												
Business IT	9.3	6.2	10.9	20.2	24.8	**71.4**	11.9	12.6	20.2	17.8	9.6	**72.1**
Support the Business[4]	20.0	3.5	7.1	8.3	3.3	**42.2**	4.6	8.1	5.7	4.8	5.7	**28.8**
Total: non-network	**29.4**	**9.7**	**17.9**	**28.5**	**28.1**	**113.6**	**16.5**	**20.7**	**25.9**	**22.6**	**15.3**	**101.0**
Total[5]	**521.0**	**360.6**	**176.9**	**143.3**	**179.7**	**1,381.6**	**158.7**	**175.0**	**172.6**	**178.6**	**206.4**	**891.3**

(1) All figures are expenditure incurred in the provision of prescribed transmission services, consistent with our Cost Allocation Methodology (CAM) approved by the AER in 2008.

(2) System Services is a new capital expenditure investment driver. It covers investments required to meet power system performance standards such as voltage control, inertia and system strength to support prescribed transmission services.

(3) Within the Security/Compliance category, we made significant investments in upgrading physical security at substations during 2016/17 and 2017/18.

(4) The office refit project that was proposed to be undertaken during the 2018-22 regulatory period has been deferred and is now forecast for early in the 2023-27 regulatory period.

(5) All figures are net of vehicle disposals.

There are no margins paid or expected to be paid to related parties in the actual/forecast expenditure reported above.

4.4.2 Performance against allowance

An allowance for the prudent and efficient capital expenditure needed to achieve the capital expenditure objectives is one of the building-block inputs to the AER's Final Decision for our current regulatory period. It is an overall allowance within which we manage and prioritise investments during the course of a regulatory period, and should not be interpreted as constraining expenditure within the specific categories identified.

At this time, we forecast our total capital expenditure to be $1.8m (0.2%) lower, than the AER's total capital expenditure allowance for the 2018-22 regulatory period. This is discussed further in Section 4.4.3.

Table 4.2 summarises our total actual capital expenditure compared to the AER's allowance in its Final Decision for the current regulatory period. Expenditure for 2020/21 and 2021/22 is based on our current forecast.

Table 4.2: Capital expenditure – AER allowance vs actual/forecast ($m real, 2021/22)[(1)]

	2017/18	2018/19	2019/20	2020/21 (forecast)	2021/22 (forecast)	Total
Allowance	175.7	176.3	179.6	186.8	174.7	**893.1**
Actual/forecast	158.7	175.0	172.6	178.6	206.4	**891.3**
Difference ($m)	(17.0)	(1.3)	(6.9)	(8.3)	31.7	**(1.8)**
Difference (%)	(9.7)	(0.7)	(3.9)	(6.6)	18.1	**(0.2)**

(1) This table is net of disposals.

4.4.3 Network capital expenditure

COVID-19 impacts on project delivery

The COVID-19 pandemic has caused some delays in the delivery of network capital expenditure in 2019/20 and this is expected to result in further delays into 2020/21. There have been disruptions or delays to specialist equipment and resources brought in from overseas, as well as necessary changes to some of our field work practices. At this time we anticipate that we will be able to catch-up some of this delay during 2021/22, which we have reflected in our current forecast expenditure for that year, although this is not certain.

The reintroduction of restrictions in response to localised outbreaks in Sydney and Brisbane in December 2020 and January 2021 highlight the difficulty in confidently planning project delivery across the whole of Queensland at this time. We will update the AER on any material changes to our actual/forecast capital expenditure as part the AER's review of our Revenue Proposal and we will update our actual/forecast capital expenditure in our Revised Revenue Proposal to be submitted in December 2021.

Load-driven capital expenditure

We forecast our load-driven capital expenditure for the 2018-22 regulatory period will be $15.2m (132%) higher than the AER's indicative allowance.

The main driver of the additional expenditure is ground clearance rectification works. These works increase the rating of our overhead transmission lines from what they would otherwise be rated, which is why they are classified as augmentation. Ground clearance rectification addresses a range of vegetation, building or ground encroachments along our 14,500km of transmission circuits. These works are being undertaken progressively over the current and next regulatory periods.

Work is underway to acquire easements to allow for replacement of a section of the Woree to Kamerunga 132kV transmission line in the Cairns area. Together with a planned second stage of easement acquisition in 2021/22, this accounts for much of the increase in expenditure in this category.

In addition, some network augmentation works that were forecast to occur late in the 2013-17 regulatory period were delayed until early in the 2018-22 regulatory period to co-ordinate with planned generator outages.

Non load-driven capital expenditure

We currently forecast that we will invest $7.4m (1.0%) less than the AER's indicative allowance for network non load-driven capital expenditure.

This forecast underspend in the current regulatory period is primarily due to increased complexity in the delivery of our extensive replacement and refit projects. This has been driven by two key changes in our operating environment:

- a low demand growth environment – this influences the scope of reinvestment projects; and
- the emergence of low system strength as a risk to secure operation of the power system – this affects how we deliver reinvestment projects.

Low demand growth

There has been a significant change in the scope of network reinvestment projects in the current regulatory period compared to those undertaken in earlier periods when there was significant forecast demand growth.

Under high demand growth conditions, the most efficient reinvestment option often includes provision for additional capacity at modest additional cost. For example, in earlier regulatory periods, we found that in many circumstances the replacement of existing assets with new assets at different substation sites, or along new transmission line easements, was the most efficient option to meet the asset condition needs as well as cater for forecast demand growth.

In contrast, when there is little or no forecast demand growth, it is critical that we focus on those assets where there is an enduring need to provide the required level of transmission services. In these circumstances the most efficient asset reinvestment is often targeted in-situ asset life extension or replacement, which is more complex than greenfield replacement options.

Low system strength

The rapid shift towards IBR, such as wind and solar photovoltaic (PV), and the displacement of traditional synchronous generation sources, has altered the performance characteristics of the transmission network. Adequate system strength levels are critical to the secure operation of the power system. Outages on the transmission network, whether planned or unplanned, can have widespread impacts on generators and customers, and can result in significant constraints on the operation of IBRs.

We are increasingly required to perform replacement activities while adjacent assets remain in service i.e. in proximity to live electrical equipment, to limit impact on the reliability and security of the network. This has necessitated new contracting, delivery and supervision models, as well as additional and more complex staging of works, to ensure the safety of our staff and contractors. This has extended some project delivery timeframes and contributed to delays in expenditure from early in the current regulatory period to the later years of the period. This has also impacted our performance under the Market Impact Component (MIC) of the Service Target Performance Incentive Scheme (STPIS) which is discussed further in Chapter 15 Service Target Performance Incentive Scheme.

The overall effect of both low demand growth and low system strength has been to extend the timeframe for reinvestment project delivery and to increase the cost per unit, though the total reinvestment expenditure is reduced compared to the 2008-12 and 2013-17 regulatory periods.

Emerging investment drivers

To ensure we can continue to adapt to the changing energy landscape, we have commenced the Next Generation Network Operations (NGNO) program to ensure we have future-ready and contemporary systems.

Our network operations are central to navigating the challenges of the energy transition and the core of our network operations is the Energy Management System (EMS). The EMS receives real-time data from thousands of measurement points from across the transmission network. It processes this data to provide situational awareness to operators in our control centre and supports the real-time operation of the power system in a safe, secure and reliable manner. Our current EMS has reached its end-of-life and is being replaced. We expect this replacement to be largely completed within the current regulatory period.

In addition to our NGNO program, system services (e.g. response to system strength, inertia and fault level issues) is an emerging driver of capital investment. We have proposed System Services as a new category of capital expenditure that was not identified at the time of our 2018-22 Revenue Proposal. The need for this additional category has emerged in the current regulatory period due to the challenges presented by our changing energy market (refer Chapter 2 Business and Operating Environment).

One such challenge is increased penetration of rooftop solar PV. This has meant that the demand for electricity supply from the transmission network during daylight hours is now often lower than the minimum demands that previously occurred overnight. These new low minimum demands lead to high voltages in certain parts of the network, which requires additional reactive power equipment to maintain voltages within their prescribed limits.

During the current 2018-22 regulatory period, we have also identified the need for additional investment to improve environmental compliance in the management of transformer oil on substation sites, as well as facilities to ensure ongoing safe systems of work for Powerlink staff and contractors within our substations.

4.4.4 Non-network capital expenditure

Our current forecast is that we will invest $9.6m (8.7%) less than the AER's indicative allowance for non-network capital expenditure in the 2018-22 regulatory period.

Within Business Information Technology (IT), renewal of our Enterprise Resource Planning and Geographical Information System platforms has been brought forward to provide more efficient integration with other initiatives within the current regulatory period. This has advanced approximately $7.0m of capital expenditure that was expected to occur in the 2023-27 regulatory period into the current 2018-22 regulatory period.

This is offset by deferral of our proposed office building refit project, which was included in the Support the Business category. This project has been deferred to the next regulatory period. The provision of office accommodation that facilitates contemporary work practices remains important for our business. However, we determined that it was more important to defer this project and focus on enhancing our network analysis, project planning and other work practices to meet the emerging technical challenges of our energy market in the short-term. In light of this decision, we intend to return the revenue attributable to the capital expenditure allowance for the office refurbishment project to customers in 2021/22.

4.5 Historical operating expenditure

Consistent with the requirements of the Rules[11], this section summarises our historical operating expenditure for the 2018-22 regulatory period. In addition to the requirements of the Rules, we have also provided our operating expenditure for the 2013-17 regulatory period, for reference.

Expenditure for the 2012/13 to 2019/20 financial years are actuals while the 2020/21 and 2021/22 financial years are based on our current expenditure plans and forecasts. All expenditure has been converted to real 2021/22 dollars using actual CPI outcomes published by the ABS and the most recent inflation forecasts published by the RBA.

We have also converted the expenditure allowance in the previous AER Final Decision[12] from real 2016/17 to real 2021/22 dollars using the same approach. This has resulted in actual expenditure and expenditure allowances reducing slightly from those published in our draft Revenue Proposal in September 2020.

4.5.1 Historical operating expenditure summary

Table 4.3 shows our actual/forecast operating expenditure for the previous and current regulatory period by expenditure category.

[11] National Electricity Rules, schedule 6A.1, clause S6A1.2(7).
[12] Final Decision Powerlink transmission determination 2017-22, Australian Energy Regulator, April 2017

Table 4.3: Operating expenditure – actual/forecast ($m real, 2021/22)(1)

	2013-17 regulatory period						2018-22 regulatory period					
	2012/13	2013/14	2014/15	2015/16	2016/17	Total	2017/18	2018/19	2019/20	2020/21 (forecast)	2021/22 (forecast)	Total
Controllable operating expenditure												
Direct operating and maintenance expenditure												
Field maintenance	65.6	69.8	71.2	70.3	83.0	**359.8**	67.5	67.7	70.3	68.9	66.3	**340.8**
Operational refurbishment	36.4	37.4	41.6	37.1	36.0	**188.5**	36.6	39.1	38.5	37.9	38.4	**190.4**
Maintenance support	14.6	15.2	14.1	15.9	13.7	**73.5**	14.1	14.4	13.9	13.4	14.6	**70.5**
Network operations	15.2	15.4	16.8	16.1	15.4	**79.0**	15.7	16.3	15.9	15.7	16.1	**79.6**
Other controllable expenditure												
Asset management support	26.1	29.0	28.4	27.8	28.9	**140.2**	27.1	26.4	24.0	24.6	25.7	**127.7**
Corporate support	27.5	28.8	45.4	53.5	51.7	**206.9**	23.7	28.4	30.2	32.8	30.4	**145.6**
Total: controllable operating expenditure	**185.4**	**195.7**	**217.5**	**220.6**	**228.6**	**1,047.8**	**184.7**	**192.3**	**192.8**	**193.2**	**191.6**	**954.5**
Non-controllable operating expenditure												
Other operating expenditure												
Insurance premiums	7.4	7.5	7.4	7.4	6.8	**36.6**	7.0	7.1	7.9	9.2	10.6	**41.9**
Self-insurance	1.7	1.7	1.9	1.8	1.9	**9.0**	1.6	1.6	1.6	1.6	1.6	**7.9**
Australian Energy Market Commission (AEMC Levy	-	-	4.2	4.4	4.5	**13.1**	4.9	5.7	6.0	5.8	5.9	**28.2**
Network support	-	-	2.9	3.9	1.9	**8.7**	-	-	-	3.1	-	**3.1**
Debt raising costs	0.6	0.6	0.6	0.5	0.6	**2.9**	0.5	0.7	0.6	0.6	0.6	**2.9**
Total: non-controllable operating expenditure	**9.7**	**9.8**	**17.0**	**18.0**	**15.8**	**70.3**	**14.0**	**15.0**	**16.1**	**20.2**	**18.6**	**84.0**
Total operating expenditure	**195.1**	**205.5**	**234.5**	**238.6**	**244.4**	**1,118.1**	**198.7**	**207.3**	**208.9**	**213.4**	**210.2**	**1,038.5**
Total operating expenditure (less debt raising costs)	194.5	204.9	233.9	238.0	243.8	1,115.2	198.1	206.6	208.3	212.9	209.6	1,035.6

(1) All figures are expenditure incurred in the provision of prescribed transmission services, consistent with our CAM approved by the AER in 2008.

4.5.2 Performance against allowance

We expect total operating expenditure to be $1,035.6m, which is $9.5m (0.9%) higher than the AER's total allowance for the 2018-22 regulatory period. These figures are exclusive of debt raising costs.

Overall, operating expenditure has been relatively steady over the 2018-22 regulatory period. We have experienced cost increases in several controllable and non-controllable operating expenditure categories as outlined in the following sections.

Table 4.4 outlines the annual trend in allowed and actual operating expenditure over the 2018-22 regulatory period.

Table 4.4: Operating expenditure – AER allowance vs actual/forecast ($m real, 2021/22)(1)

	2017/18	2018/19	2019/20	2020/21 (forecast)	2021/22 (forecast)	Total
Allowance	206.8	205.9	205.0	204.3	204.2	**1,026.1**
Actual/forecast	198.1	206.6	208.3	212.9	209.6	**1,035.6**
Difference ($m)	(8.7)	0.7	3.3	8.6	5.5	**9.5**
Difference (%)	(4.2)	0.4	1.6	4.2	2.7	**0.9**

(1) Figures are exclusive of debt raising costs.

COVID-19 impacts on operating expenditure

The full extent of the COVID-19 pandemic is not yet known. To date, in 2019/20, we adjusted maintenance practices in response to COVID-19, with some reallocation of resources, particularly in areas where travel was possible. In this way, the main impact from COVID-19 on operating practices so far has been in the balance of expenditure between categories. Several variations from typical operation include:

- modified work methodologies for field and office-based staff to respond to physical distancing requirements. This included travel limits for field staff to only faults, emergencies and critical maintenance, and the need to provide additional vehicles to ensure physical distancing requirements were met while travelling to and from work sites;
- replanning of work where COVID-19 distancing requirements could not be met, for example, the deferral of some routine maintenance activities and an increase in condition-based and corrective maintenance to prioritise staff safety while performing relevant works; and
- additional costs for management of Powerlink's COVID-19 response, for example cleaning, sanitisation and signage.

We will continue to monitor the COVID-19 situation as it evolves and ensure that we continue to operate our network in a prudent and efficient manner, consistent with our regulatory and customer obligations.

Controllable operating expenditure

Controllable operating expenditure is expected to be $1.2m (0.1%) higher in the 2018-22 regulatory period compared to the AER's allowance. Direct operating and maintenance activities comprise the largest component of controllable operating expenditure. This includes all field activities, such as maintenance, to ensure plant can perform its required functions, and network control activities to ensure the safe, secure, reliable and cost-effective operational management of the transmission network. This work is largely recurrent in nature.

A priority area over the current regulatory period has been our insulator replacement program. We identified an early life failure risk for polymer insulators, which could lead to significant safety, reliability and security risks if not addressed. We prioritised work to replace these insulators, and target those most at risk of premature failure and along major transmission flow paths such as the Queensland/New South Wales Interconnector (QNI).

Emerging operating expenditure drivers

Several key emerging drivers of expenditure have been identified in the current regulatory period.

In network operations, outage management complexities associated with the growth in IBR, and an increased focus on cyber security, have been identified as key drivers of operating expenditure in the 2023-27 regulatory period. These have had a limited impact on operating expenditure within the current regulatory period, but have been considered closely in the development of operating expenditure forecasts for the 2023-27 regulatory period (refer Chapter 6 Forecast Operating Expenditure).

A third driver is increased decommissioning activities. As assets reach the end of their service life, we look at the most efficient reinvestment approach to meet current and future capacity needs. This may include replacement of assets, reconfiguration of the network, network support arrangements or decommissioning of assets where it is economically viable to do so and we can continue to meet our reliability standards. We expect to undertake decommissioning works of approximately $9.6m on a nearly 60 year old inland transmission line between Clare and Townsville[13], and three transformers across the state, in 2021/22.

[13] This approach is in line with the preferred solution identified in the November 2019 Project Assessment Conclusions Report for the Maintaining Reliability of Supply Between Clare South and Townsville South Regulatory Investment Test for Transmission (RIT-T).

We have proactively sought to manage increased costs within our current regulatory period allowance by re-prioritising our work and by partially offsetting cost increases through efficiency improvements. These improvements include rationalised support functions and a targeted program to reduce Information Technology (IT) and Operating Technology (OT) licence costs.

Non-controllable operating expenditure

We expect to spend $8.3m (11.4%) more on non-controllable operating expenditure in the current 2018-22 regulatory period relative to the AER's allowance. This excludes debt raising costs.

Australian Energy Market Commission (AEMC) Levy

The main driver of the increase in non-controllable operating expenditure is the AEMC Levy, for which we have incurred an additional $5.8m (25.7%) above the AER's allowance for the 2018-22 regulatory period to date.

The AEMC's budget is set by Energy Ministers and is funded through a cost sharing agreement between the States and Territories. In Queensland, this cost is recovered by the Queensland Government through energy utilities including Powerlink, and is not within our control (refer Chapter 6 Forecast Operating Expenditure).

Network Support

Network support refers to costs associated with non-network solutions used as an efficient alternative to network investment, such as local generation, cogeneration, or demand side response. As the need for network support was uncertain before the start of the period, an allowance of $0 was sought and approved for the 2018-22 regulatory period. Any costs that are incurred within period are managed through the cost pass through mechanism for network support in the Rules[14].

In April 2020 AEMO declared a fault level shortfall in North Queensland, which requires Powerlink to remove the shortfall condition by August 2021. At this stage we forecast to spend approximately $3.1m for network support in the year 2020/21 to address the fault level shortfall. An application to the AER to approve the pass through of these network support costs will be made in early 2021/22.

Insurance

Insurance premiums for the 2018-22 regulatory period are forecast to be in line with the AER's allowance. We have experienced a material increase in real terms of approximately 16% in our insurance premiums for 2020/21 and expect to see a further 15% increase in real terms in 2021/22. These increases are driven by a hardening global insurance market and are anticipated to continue into the 2023-27 regulatory period, which is discussed further in Chapter 6 Forecast Operating Expenditure.

4.6 Benchmarking performance

This section provides an overview of our historical benchmarking performance based on the AER's 2020 Annual Benchmarking Report for electricity transmission. This covers capital and operating expenditure and we expect it will inform the AER's assessment of our forecast operating expenditure.

We engaged HoustonKemp to provide an independent review of our relative performance based on the information in the AER's 2020 Annual Benchmarking Report. HoustonKemp's report concluded that the AER's most recent benchmarking results for Powerlink, both in absolute and trend terms, show that we are operating relatively efficiently when compared to our Transmission Network Service Provider (TNSP) peers and have been responding to the incentives in the regulatory framework. In particular, our operating expenditure performance across major expenditure categories has been improving over time and is consistent with the key characteristics of our network relative to other stand-alone TNSPs.

We will target improvements in our productivity in the 2023-27 regulatory period to continue to drive our business hard and deliver positive customer outcomes.

We also engaged HoustonKemp to provide an independent view on the efficiency of our proposed 2018/19 operating expenditure base year and an appropriate operating expenditure productivity target. As these items relate to our forecast operating expenditure, they are discussed in more detail in Chapter 6 Forecast Operating Expenditure.

HoustonKemp's report is provided in Appendix 4.01 Efficiency of Powerlink's Base Year Operating Expenditure Report.

[14] National Electricity Rules, clause 6A.7.2.

4.6.1 Regulatory requirements

The Rules[15] 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 and capital expenditure forecasts provided by a TNSP within its Revenue Proposal represent efficient expenditure[16].

4.6.2 Our approach

We have had regard to benchmarking as part of the calculation of the trend parameter of our operating expenditure base-step-trend 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 both 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. The AER's annual benchmarking report also considers Partial Performance Indicators (PPIs), which are ratios of total costs to specific outputs such as cost per customer.

Economic benchmarking of electricity transmission businesses is impacted by the small number of TNSPs in Australia. The AER acknowledges this limitation in applying its benchmarks to TNSPs. In particular, it acknowledges that not all external factors arising from a TNSP's operating environment can be captured in the benchmark models[17].

There are also potential Operating Environment Factors (OEFs) that may be specific to one or a subset of TNSPs, which can influence outcomes. For example:

- application of different 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 particular infrastructure that another TNSP would not.

We have previously raised these factors with the AER such as within our 2018-22 Revenue Proposal[18] and discussed them with our Customer Panel and Revenue Proposal Reference Group (RPRG). We have not had specific regard to them here, other than to note that differences do exist.

Updates in the AER's 2020 TNSP Economic Benchmarking Report

We note that several adjustments have been made to the benchmarking specification in 2020 by the AER's independent consultant Economic Insights. Some of these adjustments have resulted in relatively significant changes to benchmarking results between the AER's 2019 and 2020 TNSP Economic Benchmarking Reports and rankings of TNSPs relative to each other.

One key update is a correction to the weightings applied to the non-reliability outputs to correct an error in the calculation method in previous reports. These same weightings are used in the operating expenditure base-step-trend model as part of the rate of change calculation.

The update to the weightings has placed greater importance on circuit length (its weight increased from 37.6% to 52.8%) and ratcheted maximum demand (increased from 19.4% to 24.7%) and less weight on energy throughput (reduced from 23.1% to 14.9%) and end-user customer numbers (reduced from 19.9% to 7.6%). These changes, as noted by the AER and Economic Insights, highlight that TNSPs' primary function is the transport of bulk electricity from generators to load centres[19].

The correction of this error has impacted the benchmarking results, in particular the ranking of individual TNSPs under Multilateral Total Factor Productivity (MTFP) measure, specifically:

- Powerlink and ElectraNet's MTFP results were relatively unchanged;
- TransGrid and AusNet Services have relatively lower MTFP results and rankings; and
- TasNetworks has a relatively higher MTFP result and ranking.

15 National Electricity Rules, clause 6A.31.
16 National Electricity Rules, clauses 6A.6.6(e)(4) and 6A.6.7(e)(4).
17 Annual Benchmarking Report – Electricity transmission network service providers, Australian Energy Regulator, November 2020, page 16.
18 2018-22 Revenue Proposal, Powerlink, January 2016, Section 4.6, page 28.
19 Annual Benchmarking Report – Electricity transmission network service providers, Australian Energy Regulator, November 2020, page 11.

Overall, Powerlink's relative performance compared to TransGrid and AusNet Services has therefore improved significantly. Where the 2019 TNSP Economic Benchmarking Report showed Powerlink ranked fifth out of five TNSPs for 10 of the 12 years of data displayed, the 2020 results (refer Figure 4.1) show Powerlink ranked fifth for only three of the 13 years displayed.

This correction in the benchmarking methodology demonstrates how sensitive the benchmarking model is to changes in approach or inputs. While we consider benchmarking to be a useful tool that can provide insight into a business' productivity changes over time, it is not suitable to compare absolute levels of productivity between TNSPs.

4.6.3 Independent assessment of performance

We engaged HoustonKemp to provide an independent review of our relative performance based on the information in the AER's 2020 Annual Benchmarking Report for electricity transmission, and to advise on the efficiency of our proposed base year (2018/19) to forecast operating expenditure in the 2023-27 regulatory period. The key elements of that review focused on:

- Multilateral productivity index measures such as:
  - MTFP;
  - Capital Multilateral Partial Factor Productivity (capital expenditure MPFP); and
  - Operating expenditure Multilateral Partial Factor Productivity (operating expenditure MPFP);
- PPIs that measure the ratio of total input costs to a single output, such as number of end users, circuit line length, maximum demand served and energy transported; and
- Analysis of operating expenditure category measures such as overheads per end user and maintenance costs per circuit line length.

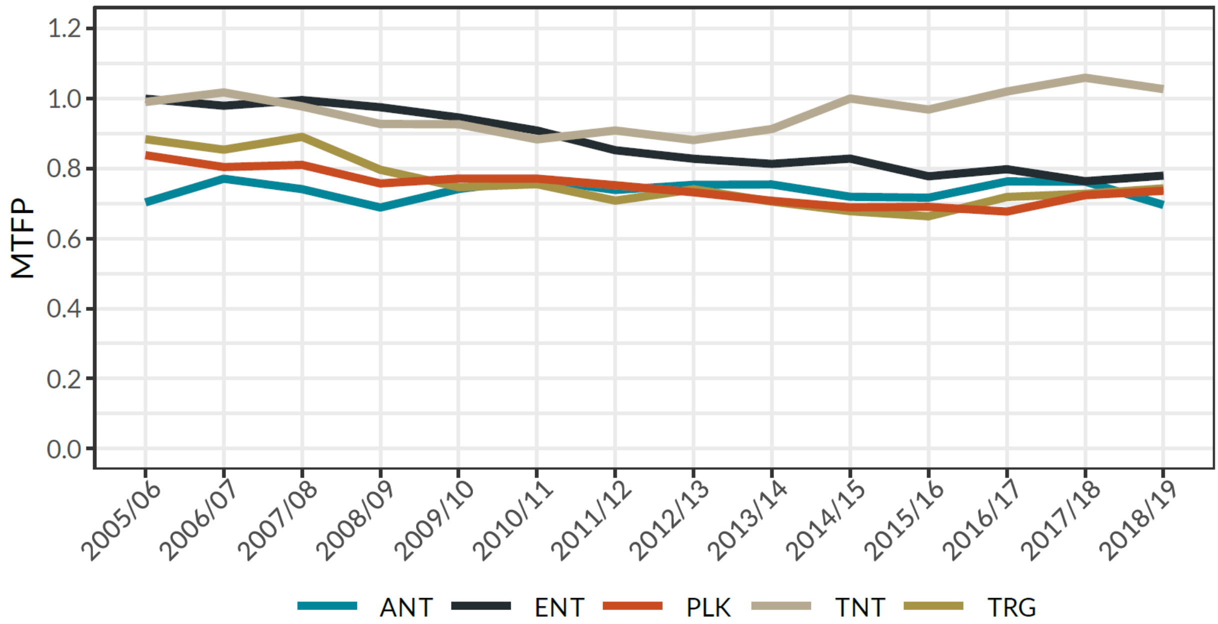
Multilateral Total Factor Productivity (MTFP)

HoustonKemp noted that our MTFP measure improved modestly in 2018/19 and that, in absolute terms, our ranking improved from fifth in 2017/18 to fourth in 2018/19 (refer Figure 4.1). The AER noted that Powerlink was one of only two TNSPs to record MTFP improvements over the last two consecutive years[20].

Our MTFP trend over time (refer Figure 4.2) shows improvement since 2016/17, which indicates that Powerlink has continued to respond to efficiency incentives in the regulatory framework, including the Efficiency Benefit Sharing Scheme (EBSS). Our significant improvement from 2016/17 to 2017/18 can largely be attributed to our 7% reduction in operating expenditure between the 2013-17 and 2018-22 regulatory periods, as acknowledged by the AER in its benchmarking report[21]. This is discussed further in the operating expenditure MPFP section.

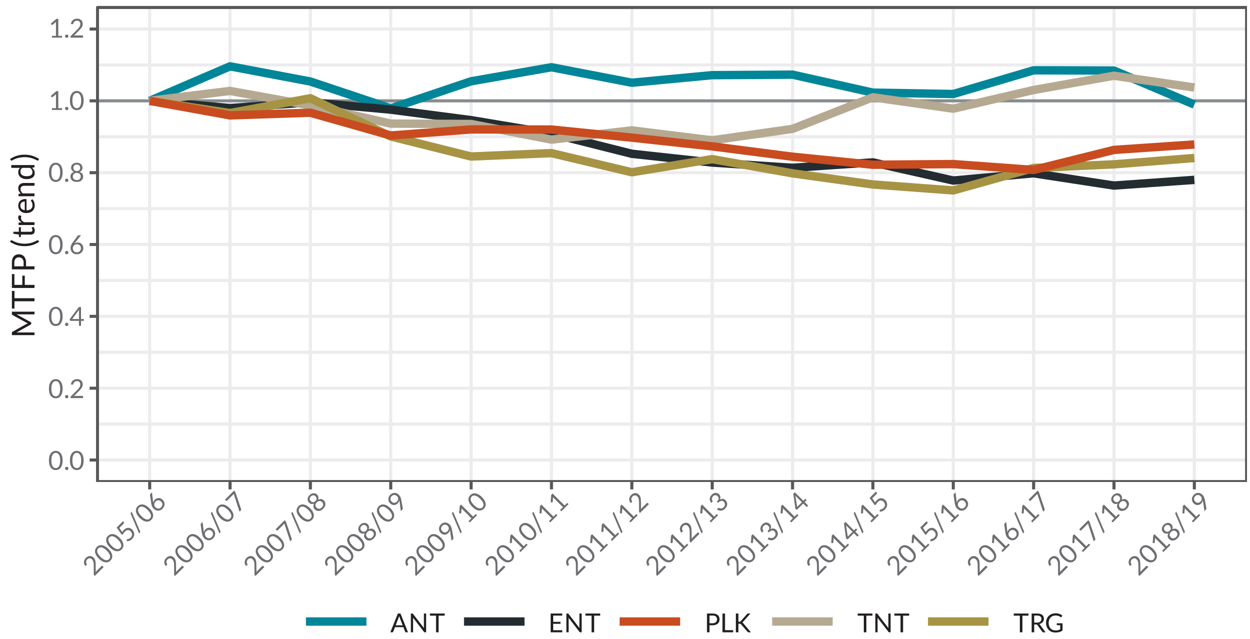
[20] *Ibid*, page. iv.
[21] *Ibid*, page 25.

Figure 4.1: Multilateral total factor productivity (absolute)



Source: Efficiency of Powerlink's base year operating expenditure, HoustonKemp, December 2020

Figure 4.2: Multilateral total factor productivity (trend)



Source: Efficiency of Powerlink's base year operating expenditure, HoustonKemp, December 2020

HoustonKemp summarised the AER's MTFP analysis as follows:

> *Powerlink's relative MTFP performance therefore places it within relatively close proximity to the outcomes for other TNSPs (with the exception of TasNetworks, whose performance reflects the outcome of the merger of transmission and distribution business and is therefore not representative of the outcomes for a stand-alone TNSP – as discussed further below), and shows improvement over time consistent with the incentives it faces under the regulatory framework*[22].

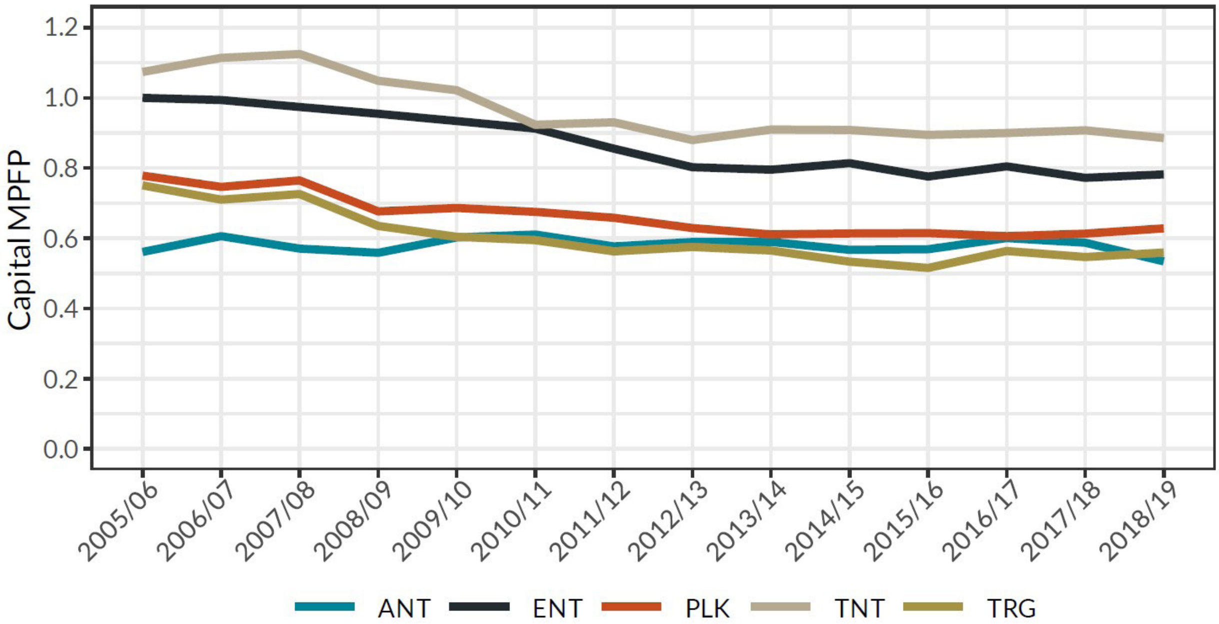
[22] Efficiency of Powerlink's base year operating expenditure, HoustonKemp, December 2020, page 14.

Capital Expenditure Multilateral Partial Factor Productivity (Capital MPFP)

The capital MPFP measure uses the quantity of physical network capacity as the capital input measure, and does not measure the value of the capital assets deployed. The inputs are the quantity of overhead lines and underground cables, measured as MVA.km, and the quantity of transformers and other assets, measured as transformer MVA.

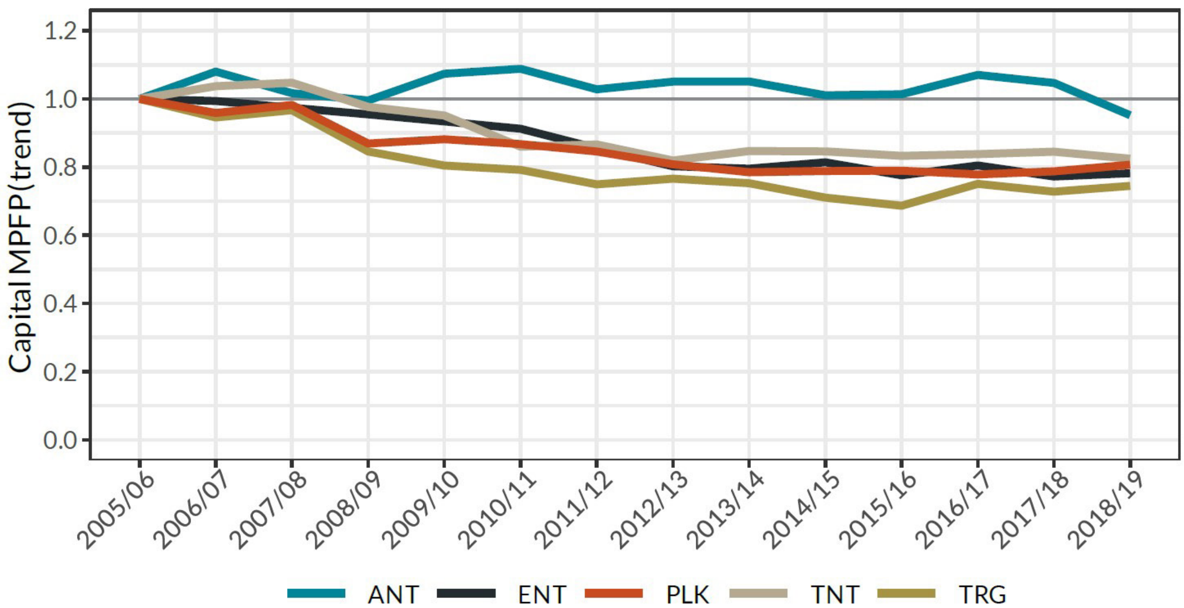
Our MPFP measure for capital improved marginally in 2018/19. However, our overall performance has been relatively flat over the last five years (refer Figure 4.3). This is primarily due to minor increases in the output measure, while the capital input measure has remained fairly constant.

Figure 4.3: Capital multilateral partial factor productivity (absolute)



Source: Efficiency of Powerlink's base year operating expenditure, HoustonKemp, December 2020

Figure 4.4: Capital multilateral partial factor productivity (trend)



Source: Efficiency of Powerlink's base year operating expenditure, HoustonKemp, December 2020

In trend terms, HoustonKemp notes that the TNSPs are grouped closely with the exception of AusNet Services, which does not undertake augmentation expenditure in Victoria as part of its regulated activities, and its capital MPFP performance is therefore different to other TNSPs (refer Figure 4.4)[23].

HoustonKemp also considered the interaction of capital and operating MPFP performance, and how this may provide indications of the efficiency of potential capital/operating expenditure trade-offs made by TNSPs. With respect to our significant reduction in operating expenditure during the 2018-22 regulatory period, and any potential impact this may have had on capital expenditure efficiency, HoustonKemp concluded:

> *Powerlink's benchmark performance for capital MPFP is relevant to the assessment of the efficiency of 2018/19 opex only to the extent that it may provide indications of the efficiency of the capex/opex trade-off made by Powerlink relative to other TNSPs. There is nothing in the latest benchmarking analysis to suggest that there are any concerns with this trade-off, as evidenced by the generally consistent capital MPFP outcomes between Powerlink and the other TNSPs, and Powerlink's relative performance overall under the AER's MTFP analysis*[24].

We note our relatively flat capital benchmarking performance over the past five years does not measure the cost to customers of capital investments. However, the value of our RAB has declined and is forecast to continue to decline, which does provide ongoing cost reductions to customers. We consider this provides a reasonable indication of our prudent asset management and reinvestment approach. This is discussed further in Chapter 8 Regulatory Asset Base.

Operating Expenditure Multilateral Partial Factor Productivity (Operating MPFP)

Our MPFP measure for operating expenditure remained relatively flat in 2018/19, after a significant improvement achieved in 2017/18 (refer Figure 4.5). This improvement was primarily related to our operating expenditure reduction of approximately 7% between the 2013-17 and 2018-22 regulatory periods. None of the TNSPs showed significant growth (in trend terms) in 2018/19 (refer Figure 4.6).

Our ability to maintain this reduction and live largely within the AER's allowance throughout the current regulatory period demonstrates that efficiencies realised from our business restructure process in 2016/17 have been sustained. HoustonKemp stated that:

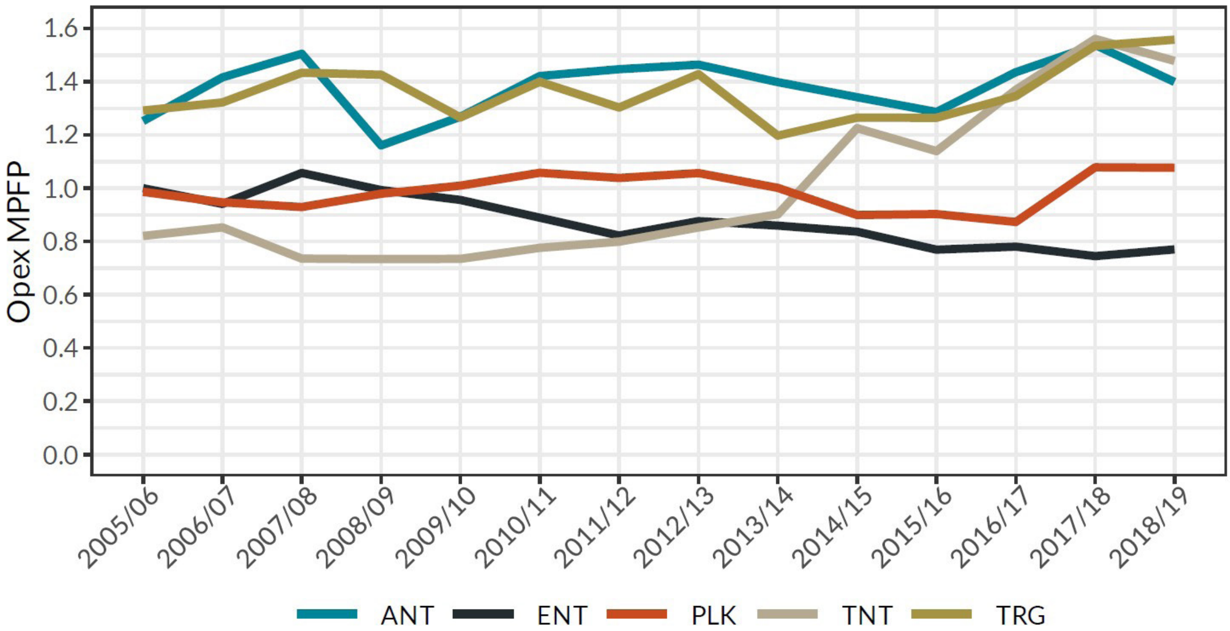
> *The recent improvement in Powerlink's MTFP discussed above is almost entirely due to its improvement in opex MPFP. This strongly supports the conclusion that Powerlink is responding to the incentives in the regulatory framework, and that revealed 2018/19 opex can be presumed to be efficient*[25].

It is also important to recognise TasNetwork's operating expenditure performance as a significant contributor to the industry productivity trend and that it is not a relevant comparator for Powerlink. The AER and HoustonKemp both noted that while TasNetworks has improved its operating expenditure MPFP performance significantly since 2014/15, these efficiency gains coincide with the merger of Tasmania's DNSP (Aurora Energy) and TNSP (Transend) to form TasNetworks[26,27]. As a result, HoustonKemp observed that:

> *The efficiency gains made by TasNetworks resulting from the merger, reflected in its TNSP benchmarking results, do not represent gains that are also available to a stand-alone TNSP such as Powerlink. As a consequence, it is most relevant to compare Powerlink's benchmarking outcomes to the other TNSPs excluding TasNetworks*[28].

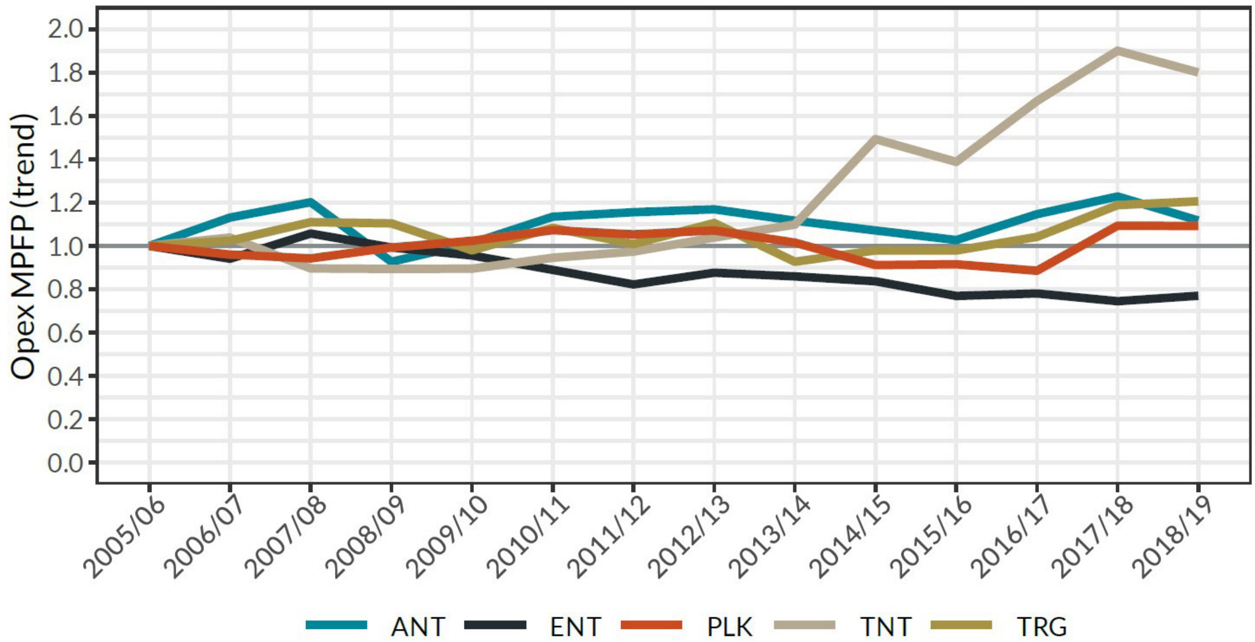
23 *Ibid*, page 17.
24 *Ibid*, page 18.
25 *Ibid*, page 14.
26 *Ibid*.
27 Annual Benchmarking Report – Electricity transmission network service providers, Australian Energy Regulator, November 2020, page 25.
28 Efficiency of Powerlink's base year operating expenditure, HoustonKemp, December 2020, page 15.

Figure 4.5: Operating expenditure multilateral partial factor productivity (absolute)



Source: Efficiency of Powerlink's base year operating expenditure, HoustonKemp, December 2020

Figure 4.6: Operating expenditure multilateral partial factor productivity (trend)



Source: Efficiency of Powerlink's base year operating expenditure, HoustonKemp, December 2020

HoustonKemp made the following concluding remarks on our operating expenditure MPFP results:

> *Consistent with its relative MTFP performance, Powerlink's relative opex MPFP performance places it within relatively close proximity to the outcomes for other TNSPs (with the exception of TasNetworks, whose performance is not representative of the outcomes for a stand-alone TNSP). Further, Powerlink's opex MPFP shows improvement over time, consistent with Powerlink responding to the incentives it faces under the regulatory framework*[29].

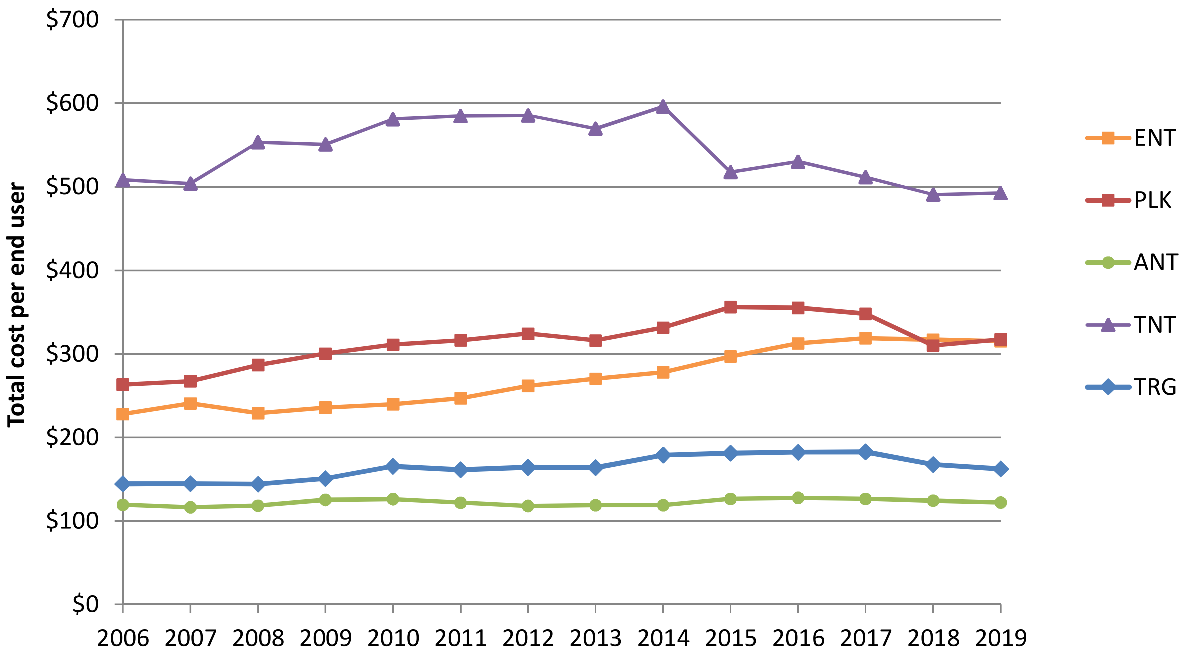
[29] Efficiency of Powerlink's base year operating expenditure, HoustonKemp, December 2020, page 16.

Partial Performance Indicators (PPIs)

In its Annual Benchmarking Report the AER publishes PPIs, which provide a simple representation of the input costs used to produce particular outputs by TNSPs, and can be used to provide a general indication of comparative performance in delivering one type of output. The AER notes that as PPIs do not take interrelationships between the different outputs into account, PPIs are most useful when used in conjunction with other top-down benchmarking techniques[30].

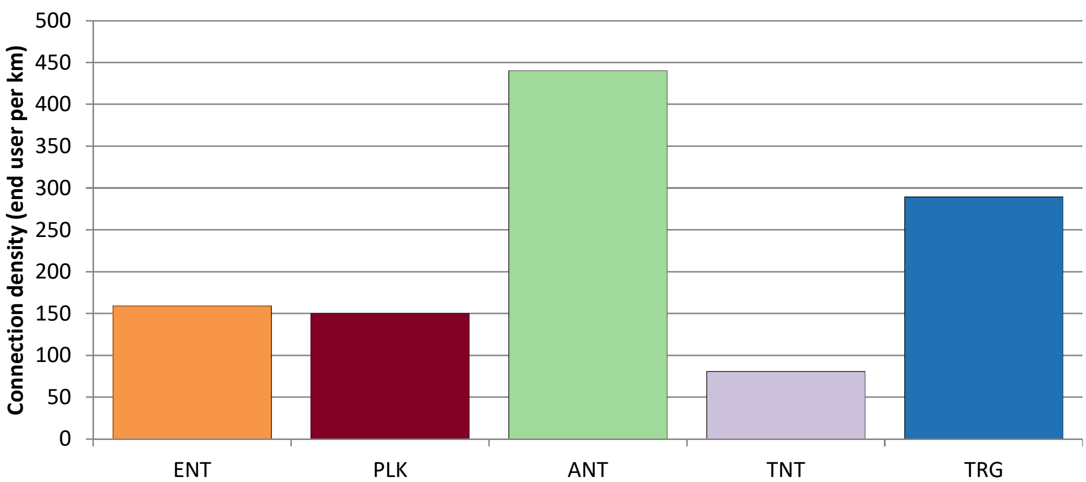
On the measure of total cost per end user Powerlink ranks equal with ElectraNet, behind AusNet Services and TransGrid but ahead of TasNetworks (refer Figure 4.7). These relative rankings are consistent with average connection density of the various TNSPs, measured as the number of end users per circuit kilometre (refer Figure 4.8). Our relative performance across a number of PPIs over time shows our performance in 2018/19 substantially improved over our 2014/15 results, which was our previous operating expenditure base year (refer Figure 4.9).

Figure 4.7: TNSP total cost per end user



Source: Annual Benchmarking Report – Electricity transmission network service providers, Australian Energy Regulator, November 2020

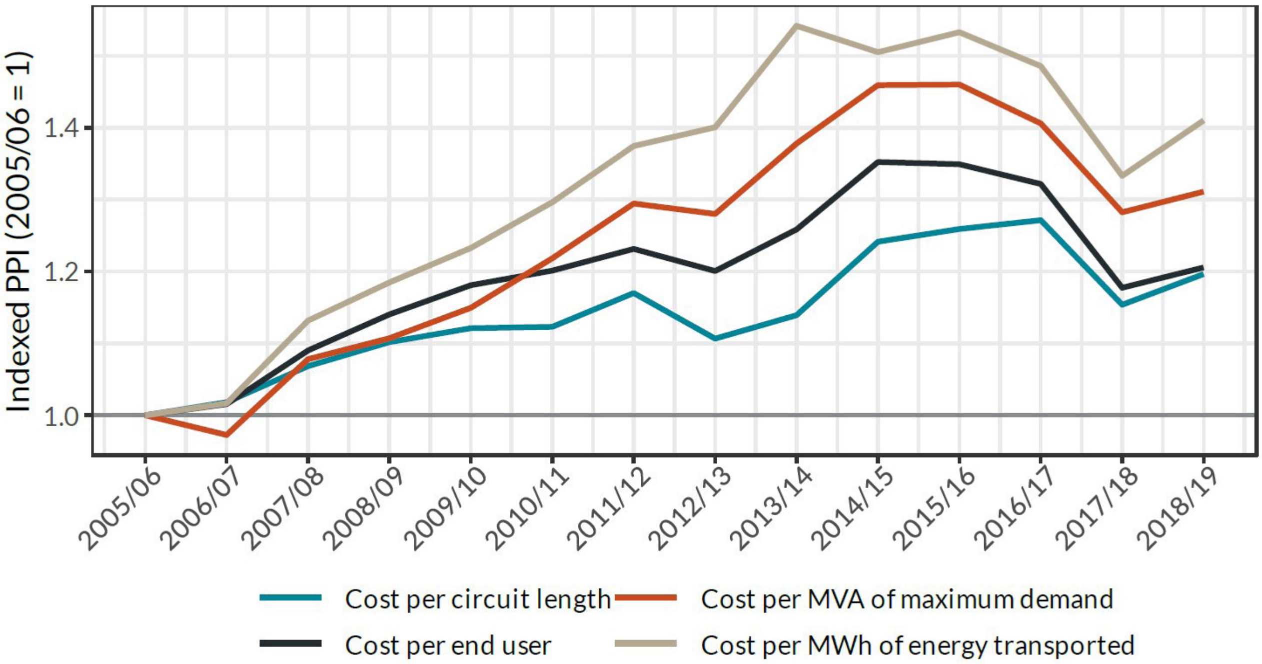
Figure 4.8: TNSP connection density (end users per km)



Source: Annual Benchmarking Report – Electricity transmission network service providers, Australian Energy Regulator, November 2020

30 Annual Benchmarking Report – Electricity transmission network service providers, Australian Energy Regulator, November 2020, page 29.

Figure 4.9: Powerlink's PPI performance over time, 2005/06 to 2018/19



Source: Efficiency of Powerlink's base year operating expenditure, HoustonKemp, December 2020

HoustonKemp also had regard to our PPIs and made the following observations in relation to PPI results. This was considered particularly with regard to our proposed 2018/19 base year.

> *The AER's PPI analysis shows that although Powerlink has the second-highest total cost per end user, this is consistent with it having the second lowest connection density (end users per circuit length), and therefore an unsurprising outcome. The PPI analysis also shows that Powerlink's total cost per end user has been falling since 2014/15, although it did increase slightly in 2018/19 (in the order of two per cent).*
>
> *Powerlink ranked third in total cost per circuit length and total cost per MVA of maximum demand served, improving its cost per MVA ranking in 2018/19. Its performance, once adjusted to reflect its network characteristics, is therefore not an outlier on either of these metrics.*
>
> *Powerlink has generally reduced its costs per MWh of energy transported since 2013/14, although there was a modest increase in this metric in 2018/19 (in the order of less than six per cent). Even with this change Powerlink's cost per MWh of energy has decreased by nine per cent since 2013/14*[31].

HoustonKemp then concluded:

> *To summarise, taken together [with Powerlink's MTFP and MPFP results], there is nothing in the AER's PPI analysis that would give rise to a concern that Powerlink's 2018/19 outturn opex is materially inefficient*[32]*, warranting further detailed analysis of revealed costs*[33].

4.6.4 Summary of benchmarking performance

HoustonKemp's review indicates that our capital and operating expenditure during the current regulatory period is in line with other TNSPs. Other performance metrics and PPIs explored by the AER in their 2020 Annual Economic Benchmarking Report also indicate that Powerlink's performance is in line with expected trends and does not suggest that we are operating inefficiently compared to other TNSPs.

HoustonKemp concluded the following with respect to the AER's benchmarking results:

> *Powerlink's productivity benchmarking results, both in absolute and trend terms, suggest that it is operating relatively efficiently when compared to other TNSPs in the NEM, particularly taking into account the non-comparability of TasNetworks' benchmarking outcomes*[34].

31 Efficiency of Powerlink's base year operating expenditure, HoustonKemp, December 2020, page 19
32 'Materially inefficient' reflects terminology used consistently by the AER.
33 Efficiency of Powerlink's base year operating expenditure, HoustonKemp, December 2020, page 20.
34 *Ibid.*

4.7 Summary

The analysis in this chapter demonstrates that we have reduced our costs and responded to changes in our operating environment. This has contributed to improvements in benchmarking performance during the current regulatory period.

We have adopted a structured Innovation Framework to provide a foundation for further productivity improvement and to improve customer outcomes.

Our capital expenditure reflects an environment with little or no demand growth where the majority of capital expenditure is reinvestment in assets that have reached reach the end of their technical and economic life. Total actual/forecast capital expenditure is forecast to be around 0.2% lower than the AER's allowance for the current regulatory period.

Total actual/forecast operating expenditure has reduced by 7% compared to the 2013-17 regulatory period excluding debt raising, and is expected to be within 0.9% of the AER's allowance for the current regulatory period.

5. Forecast Capital Expenditure

5.1 Introduction

This chapter presents Powerlink's forecast capital expenditure for each year of the 2023-27 regulatory period.

Key highlights:

- We have responded to the feedback received from our customers, the Australian Energy Regulator (AER), and the AER's Consumer Challenge Panel (CCP23) to our draft Revenue Proposal. In focusing on how we can more prudently and efficiently manage our network, our forecast capital expenditure has reduced by more than 12% since our draft Revenue Proposal in September 2020.
- Our forecast capital expenditure for the 2023-27 regulatory period is $863.9m.
  - This is $27.4m (3.1%) lower than actual/forecast capital expenditure for the 2018-22 regulatory period.
  - The majority of this forecast ($726.1m or 84%) is non load-driven network expenditure.
- The key drivers that underpin our forecast for the 2023-27 regulatory period are:
  - forecast continued decline in minimum demand and energy delivered to Queensland customers;
  - our response to the changing energy market environment including the growth in deployment of Inverter-Based Resources (IBR); and
  - targeted reinvestment in the transmission network to maintain security, reliability and quality of supply as our assets continue to age.
- Our Hybrid+ forecasting approach integrates top-down and bottom-up methods, with project-specific justification provided for approximately 70% of our forecast capital expenditure.
- We have proposed one contingent project and decided not to continue to pursue contingent reinvestments in our Revenue Proposal, which is a change from the position in our draft Revenue Proposal in response to customer and AER feedback.

5.2 Regulatory requirements

The National Electricity Rules (the Rules)[1] require that our Revenue Proposal provides information on our capital expenditure for each year of the previous and current regulatory periods. The Rules[2] also require that the 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[3] (our Expenditure Forecasting Methodology). This methodology, and our forecasts, must also have regard to the AER's 2013 Expenditure Forecast Assessment Guideline for Electricity Transmission.

We must submit our forecast capital expenditure for the 2023-27 regulatory period based on the requirements set out in the Rules[4].

5.2.1 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 5.1 and discussed in detail in Appendix 5.01 Operating and Capital Expenditure Criteria and Factors.

1 National Electricity Rules, schedule 6A.1, clause S6A.1.1(6).
2 National Electricity Rules, clause 6A.6.7(e)(5).
3 National Electricity Rules, clause 6A.10.1B.
4 National Electricity Rules, clause 6A.6.7 and schedule 6A.1.

Table 5.1: How we meet the capital expenditure objectives

Capital expenditure objective	How our proposal meets this objective
Meet or manage the expected demand for prescribed transmission services over the period	Demand is forecast to be relatively constant across our network over the 2023-27 regulatory period, in line with minimal growth seen over the 2018-22 regulatory period. Our reinvestment forecast excludes any assets we have identified that can be retired at their end of life without replacement.
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* and as a registered Transmission Network Service Provider (TNSP) in the National Electricity Market (NEM). As a company we are also subject to various other environmental, cultural heritage, planning approval, Workplace Health & Safety, financial and other regulations. Our compliance with these regulatory obligations and requirements is encompassed in our Asset Management Framework and associated policies and procedures, which provide the foundation for our capital expenditure activities. These are provided as supporting documents to 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 for maintaining the safety of the transmission system while maintaining and meeting the mandated level of quality, reliability and security of supply to customers. Where there are no mandated service levels we will maintain the existing levels of service.

5.3 Capital expenditure categories

We have largely retained the same categories of capital expenditure drivers as applied in both our 2013-17 and 2018-22 regulatory periods. As noted in our Expenditure Forecasting Methodology, we have included a new category of expenditure driver, System Services. This new category of capital expenditure is forward-looking and does not require the reclassification of any historical capital expenditure.

Our capital expenditure categories, and the prescribed transmission services they relate to, are shown in Table 5.2.

Table 5.2: 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 (DNSP's) or other TNSPs. Associated works are identified through joint planning with the relevant Network Service Provider (NSP).	Exit services
Easements	The acquisition of transmission line easements to facilitate the projected expansion and reinforcement of the transmission network. This includes land acquisitions associated with the construction of substations or communication sites.	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, and asset reliability or safety requirements. A range of options are considered for asset reinvestments including, removal without replacement, non-network alternatives, life extension to extend technical life or replacement with assets of the same or different type, configuration or capacity. Each option is considered in the context of future capacity needs accounting for forecast demand and the changing mix and location of generation.	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, which are regarded as critical infrastructure.	Common services, TUOS services and entry/exit services
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 and replace or improve business system functionality where appropriate.	Common services
Support the Business	Expenditure to replace or improve business requirements including, commercial buildings, motor vehicles and other tools and equipment.	Common services

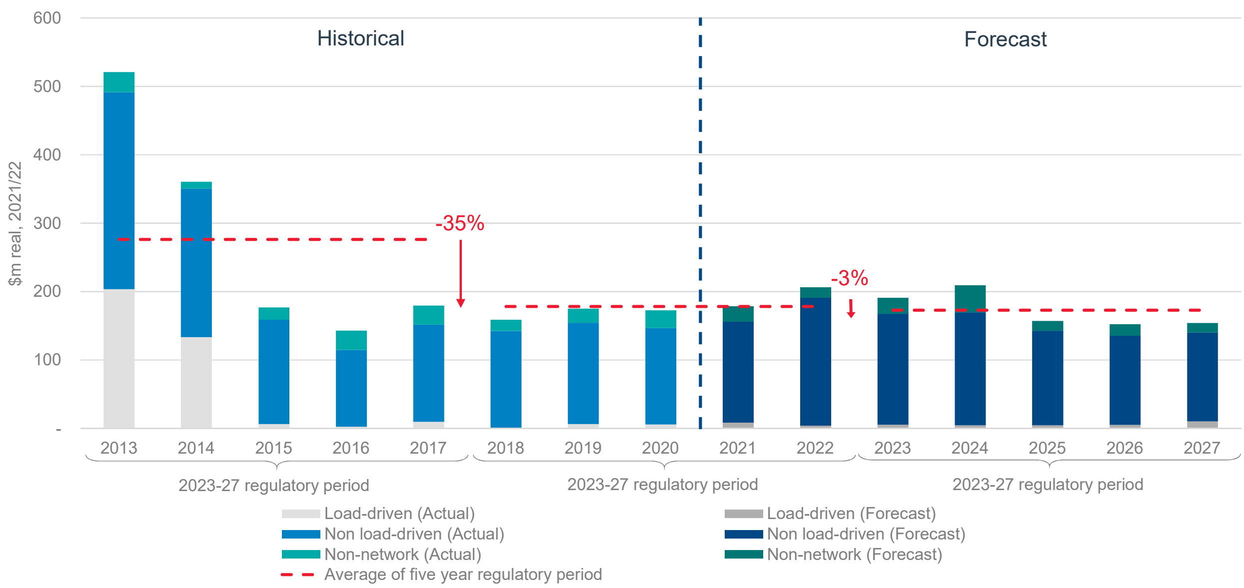
5.4 Forecast capital expenditure overview

This section presents our forecast capital expenditure for the 2023-27 regulatory period.

5.4.1 Forecast capital expenditure

Our total forecast capital expenditure for the 2023-27 regulatory period, along with our actual/forecast expenditure for the previous and current regulatory periods, is shown in Figure 5.1.

Figure 5.1: Capital expenditure by driver ($m real, 2021/22)



Our total forecast capital expenditure is $863.9m, which is $27.4m (3.1%) lower, than the actual/forecast expenditure for the 2018-22 regulatory period. The majority of this ($726.1m or 84%) is non load-driven network expenditure.

Our forecast expenditure by category is shown in Table 5.3. Further details about the forecast by category is provided in Section 5.6.

Table 5.3: Forecast capital expenditure by category ($m real, 2021/22)(1)

Category	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Network capital expenditure						
Load-driven capital expenditure						
Augmentations	3.4	2.1	1.1	0.1	-	6.7
Connections	-	-	-	-	2.4	2.4
Easements	2.0	2.5	3.4	5.1	8.2	21.1
Total: load-driven	**5.4**	**4.6**	**4.5**	**5.2**	**10.5**	**30.2**
Non load-driven capital expenditure						
Reinvestments	143.2	150.1	132.6	124.7	124.2	674.8
System Services	13.2	9.3	-	-	-	22.5
Security/compliance	2.9	2.9	2.9	2.9	2.9	14.5
Other	2.9	2.9	2.9	2.9	2.9	14.3
Total: non load-driven	**162.2**	**165.1**	**138.3**	**130.5**	**130.0**	**726.1**
Non-network capital expenditure						
Business IT	15.8	13.7	9.5	11.5	8.8	59.3
Support the Business	7.5	26.1	4.9	5.2	4.7	48.4
Total: non-network	**23.3**	**39.8**	**14.4**	**16.7**	**13.5**	**107.7**
Total	**190.9**	**209.4**	**157.2**	**152.4**	**154.0**	**863.9**

(1) This table is net of disposals.

Our forecast capital expenditure reflects the key drivers for investment described in our Business Narrative (refer to Appendix 2.01) and in Chapter 2 Business and Operating Environment. In particular:

- our forecast load-driven capital expenditure reflects the outlook of minimal growth in peak demand. More than two thirds of the forecast expenditure in these categories is for easement acquisition, primarily for the Queensland/New South Wales Interconnector (QNI) Medium upgrade project;
- reinvestment in existing network assets accounts for nearly 80% of the total forecast capital expenditure. The most significant drivers for this reinvestment are to address increasing levels of corrosion across our fleet of over 23,500 steel transmission towers[5], and the cyclical replacement of digital technologies that protect and control our high voltage assets due to obsolescence/lack of support and spares; and
- investment in network assets to ensure we continue to meet the prescribed standards of power system technical performance as minimum demand decreases and there is greater variability in power flows across the network.

To meet these challenges we also need to continue to invest in the facilities and tools that support our people. Our forecast non-network capital expenditure includes provision for a major refit of our office facilities which will enable more efficient use of the available space as well as replacement and renewal of our legacy IT systems.

5.4.2 Changes from the draft Revenue Proposal

Our draft Revenue Proposal included total forecast capital expenditure of $988.9m, which is $97.6m (11%) higher than the actual/forecast capital expenditure for the 2018-22 regulatory period.

Since we published our draft Revenue Proposal we have continued to focus on how we can more prudently and efficiently manage the network while continuing to deliver safe and reliable electricity transmission services for customers. We continue to challenge ourselves on the needs for proposed investments. These activities have occurred in parallel with the development of our 2020 Transmission Annual Planning Report (TAPR) included in Appendix 5.02, and our annual asset management planning cycle, which concluded in December.

Key items which have contributed to the substantial reduction in forecast capital expenditure are:

- removal of some proposed projects where the need for capital expenditure in the 2023-27 regulatory period could not be robustly demonstrated at this stage;
- critical review of the scope of some of the major transmission line life extension projects. For example, for the Ross to Chalumbin 275kV transmission line we have been able to identify specific sections of the line where the condition has deteriorated more significantly and have been able to better target the scope of life extension works;
- critical review of the unit costs for reinvestment projects, particularly for secondary systems replacement projects. We are investigating the potential for more cost-effective ways to deliver these projects through replacing selected equipment within existing panels. For secondary systems projects we have set ourselves the stretch target of reducing the per unit costs for these projects by 10% compared to our current approach; and
- recalibration of the asset mean replacement lives used in the Repex Model based on the most recent five years of actual condition-based replacement quantities. As a result the mean replacement lives are now slightly longer than the lives determined in our previous AER determination.

We have also updated our forecasts to reflect the latest inflation forecast, as published by the Reserve Bank of Australia (RBA) in November 2020.

As a result of these reviews and consistent with our commitment to affordability, we have been able to reduce our total forecast capital expenditure for the 2023-27 regulatory period by $125.0m (12.6%) compared to our draft Revenue Proposal. Our view is that this forecast responds to feedback we received on the draft Revenue Proposal which highlighted that a 12% increase in capital expenditure (compared to the current regulatory period) was a serious concern for our customers. Importantly, it also reflects our commitment to delivering electricity transmission services prudently and at an efficient cost.

Table 5.4 summarises the difference in total forecast capital expenditure between our draft Revenue Proposal and our Revenue Proposal.

[5] This increasing corrosion is a normal feature of the lifecycle of steel transmission towers and the rate varies depending on local climatic conditions.

Table 5.4: Capital expenditure – draft Revenue Proposal vs Revenue Proposal ($m real, 2021/22)(1)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Draft Revenue Proposal	200.7	191.5	180.4	208.2	208.1	**988.9**
Revenue Proposal	190.9	209.4	157.2	152.4	154.0	**863.9**
Difference ($m)	(9.8)	17.9	(23.2)	(55.8)	(54.1)	**(125.0)**
Difference (%)	(4.9)	9.3	(12.9)	(26.8)	(26.0)	**(12.6)**

(1) This table is net of disposals.

5.5 Capital expenditure forecasting methodology

We have developed our capital expenditure forecast consistent with the requirements of the Rules[6] and our Expenditure Forecasting Methodology, which was provided to the AER in June 2020. In the course of developing our capital expenditure forecast we made several small refinements to our forecasting methodology (refer to Appendix 5.03 Expenditure Forecasting Methodology). The most significant change is that the detailed methodology for integration of top-down and bottom-up forecasts is no longer required. The top-down forecasts are now complementary to, and do not overlap with, the bottom-up forecasts so the total capital expenditure forecast is simply the addition of the top-down elements with the bottom-up elements. We have also had regard to the AER's 2019 Industry Practice Application Note for Asset Replacement Planning[7].

While we have specific project estimates for significant investments we also use the AER's Replacement Expenditure (Repex) Model to support an additional element of the capital expenditure forecasts. The Repex Model takes a top-down approach to forecast part of our network reinvestment expenditure under our Hybrid+ approach (explained further in Section 5.5.2). We have adapted the AER's Repex Model to better reflect our asset management planning practices. In particular, where our planning has identified opportunities to retire assets without replacement at their end of life these have been excluded from the forecast.

We have also had regard to information on proposed transmission investments within a 10 year outlook, as published in our TAPR and related material[8], our 30 year Network Vision[9] and Australian Energy Market Operator's (AEMO's) 2020 Integrated System Plan (ISP).

As we developed our methodology and forecasts for the 2023-27 regulatory period, we regularly engaged with our customers and stakeholders (refer Chapter 3 Customer Engagement). We also engage with our customers and stakeholders on planning and other business related matters in the normal course of business, including at our annual Transmission Network Forum[10].

Our capital expenditure forecasts are limited to investment or reinvestment in assets that provide prescribed transmission services, consistent with our Cost Allocation Methodology (CAM) approved by the AER in 2008. Where a single project cost estimate includes expenditure on both prescribed and non-prescribed assets, the proportion of expenditure attributable to assets that provide prescribed transmission services is included in our capital expenditure forecasts. Our Repex Model includes only those assets that are allocated to the provision of prescribed transmission services.

5.5.1 Key drivers of our capital expenditure forecast

There are a number of significant external drivers that have influenced our capital expenditure program in the current regulatory period and are also expected to continue to have an impact in the 2023-27 regulatory period. These are summarised in Table 5.5.

6 National Electricity Rules, clause 6A.6.7.
7 Industry practice application note - Asset replacement planning, Australian Energy Regulator, January 2019.
8 2020 Transmission Annual Planning Report, Powerlink, https://www.powerlink.com.au/reports/transmission-annual-planning-report-2020.
9 Network Vision, Powerlink, https://www.powerlink.com.au/network-vision.
10 Engagement Forums, Powerlink, https://www.powerlink.com.au/engagement-forums.

Table 5.5: Key capital expenditure drivers

Key driver	Description
Continued decline in consumption	AEMO's Central scenario in its Electricity Statement of Opportunities (ESOO) forecasts a continued decline in energy consumption over our 2023-27 regulatory period[1]. This includes a rapid decline in minimum operational demand as a result of continued growth in solar PV generation to meet daytime demand. AEMO also highlighted the considerable uncertainty surrounding its forecasts, primarily due to the COVID-19 pandemic.
COVID-19	As explained in Chapter 4 Historical Capital and Operating Expenditure, COVID-19 has impacted the timing of the delivery of some of our projects. This is a result of delays in sourcing specialist equipment and resources from overseas, as well as necessary changes to work practices. We expect to be able to catch-up some of this delay in 2021/22.
Inverter-Based Resources	We have also discussed the impact of the rapid growth in IBR on our network, which includes grid-connected and rooftop solar PV, wind farms and battery technologies. This has resulted in the creation of a new category of expenditure for System Services. It also impacts how we plan and deliver projects as we seek to efficiently minimise network outages in an environment of reduced synchronous generation capacity.
An ageing network	The average age of our network has continued to increase during the 2018-22 regulatory period. While age alone is not a trigger for individual asset reinvestments, the trend in the average age of the fleet of assets can indicate the likely need for more or less expenditure on asset renewal.
Cyber security	TNSPs are considered amongst the highest criticality segment under the Australian Energy Sector Cyber Security Framework (AESCSF). Cyber security has therefore received increased focus in the current regulatory period and this will continue to be the case into the 2023-27 regulatory period. We have critically reviewed the need for any material additional expenditure driven by cyber security requirements. While we currently consider that it will be sufficient to maintain our current level of capability, in December 2020 the Commonwealth Government proposed changes to legislation[2] which result in elevated security obligations and standards on Australian critical infrastructure owners and operators. Given the uncertainty around the scope and timing of these future formal obligations, we have not included additional capital expenditure in our forecasts at this time.

(1) 2020 Electricity Statement of Opportunities, Australian Energy Market Operator, August 2020.

(2) *Security Legislation Amendment (Critical Infrastructure) Bill 2020.*

5.5.2 Our Hybrid+ approach

We continue to apply a hybrid approach to develop our capital expenditure forecasts, which integrates top-down and bottom-up methods. We applied this hybrid approach to forecast our capital expenditure in our 2018-22 Revenue Proposal.

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 2023-27 regulatory period. A key improvement includes the provision of project-specific supporting justification for over 70% of our total forecast capital expenditure. Dependent on the type of proposed investment this justification may include condition assessment reports, specific asset strategies, project scopes and estimates, network planning assessments and risk/cost quantification[11]. This bottom-up information provides justification for the primary expenditure forecast for these significant investments. This is complemented by the top-down forecast for the remaining assets.

We refer to this further development as the Hybrid+ approach. This approach provides a number of advantages in that it:

- reduces the cost to Powerlink (and ultimately customers) of preparing our Revenue Proposal compared to a fully bottom-up approach;
- assists the AER and stakeholders in terms of the time, effort and cost to review and assess our Revenue Proposal; and
- balances the desire of stakeholders to understand the technical and economic justification for significant investments with the uncertainty of forecasting capital expenditure needs many years in advance, all while the technical demands on the transmission network are rapidly changing through the energy transition.

Details of the Hybrid+ approach can be found in Appendix 5.03 Expenditure Forecasting Methodology and a summary is presented in Table 5.6.

11 As part of the material submitted in support of our Revenue Proposal we have included a guide to assist stakeholders understanding of this supporting documentation.

Table 5.6: Application of the Hybrid+ approach

Approach	Application	Method
Bottom-up	Approved projects. Load-driven capital expenditure. Power transformer and Static Var Compensator (SVC) reinvestment. Any major one-off expenditure needs. System services such as system strength and inertia. Significant network projects (indicative threshold of >$12.0m project cost). Contingent projects (these do not form part of the ex-ante capital expenditure forecast).	Analysis of need, preparation of project scope, estimate, planning statement and risk/cost assessment.
Top-down	Network assets including transmission lines, substations (excluding transformers which are bottom-up) and secondary systems.	Use of the AER's Repex Model.
Trend analysis	Security/compliance. Other network capital expenditure, including reinvestment in substation auxiliary systems and buildings.	Trend of recent expenditure with outliers removed.

In adopting our Hybrid+ approach we set a target of at least 60% of our forecast capital expenditure in the 2023-27 regulatory period being based on bottom-up methods. We received feedback on our draft Revenue Proposal from customers and the AER's CCP23 seeking more detail around what proportion of the capital expenditure forecasts are derived from bottom-up versus top-down techniques. Table 5.7 summarises the proportion of bottom-up and top-down forecasts for each of the major categories of capital expenditure.

Table 5.7: Proportion of bottom-up and top-down forecasts ($m real, 2021/22)

Capital expenditure category	Forecast $	Bottom-up	Top-down
Augmentation	6.7	100%	0%
Connections	2.4	100%	0%
Easements	21.1	100%	0%
Reinvestment	674.8	79%	21%
- Transmission lines	243.6	89%	11%
- Substation primary plant	145.5	73%	27%
- Substation secondary systems	219.0	65%	35%
- Telecommunications	60.2	100%	0%
- Network switching centre	6.4	80%	20%
System services	22.5	100%	0%
Security / Compliance	14.5	0%	100%
Other	14.3	0%	100%
Business IT	59.3	51%	49%
Support the Business	48.4	85%	15%
Total	**863.9**	**76%**	**24%**

While full bottom-up analysis is not currently available, nor expected to be available, for all future capital investments, 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 Regulatory Investment Test for Transmission (RIT-T) process.

5.5.3 Key inputs and assumptions

The key inputs and assumptions we applied to develop our forecast capital expenditure for the 2023-27 regulatory period are summarised in Table 5.8. Powerlink's Directors have certified the reasonableness of the key assumptions (refer to Appendix 1.01 Board Certification of Key Inputs and Assumptions).

We have also included a brief guide to our key inputs and assumptions for capital expenditure in Attachment 1.

Table 5.8: Inputs and assumptions for our capital expenditure forecast

Input/assumption	Sources and approach
Forecast demand and generation	• For our electricity demand forecast, we use the Central Scenario in AEMO's 2020 ESOO. • 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 DNSP's.
Integrated System Plan	• AEMO's 2020 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.
Transmission reliability of supply standard	• Clause 6.2 of our Transmission Authority 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.
Asset information	• Our Hybrid+ forecasting methodology requires substantial information on the current fleet of assets and equipment installed on our network. We source 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), various metals commodities (aluminium, copper and steel) and general plant and equipment. • The cost escalators we have applied are outlined in Chapter 7 Escalation Rates and Project Cost Estimation.
Repex Model unit rates	• An explanation of our approach to develop the unit rates for our Repex Model is included in Chapter 7 Escalation Rates and Project Cost Estimation.

The following sections detail how each key input has been integrated into our capital expenditure forecast.

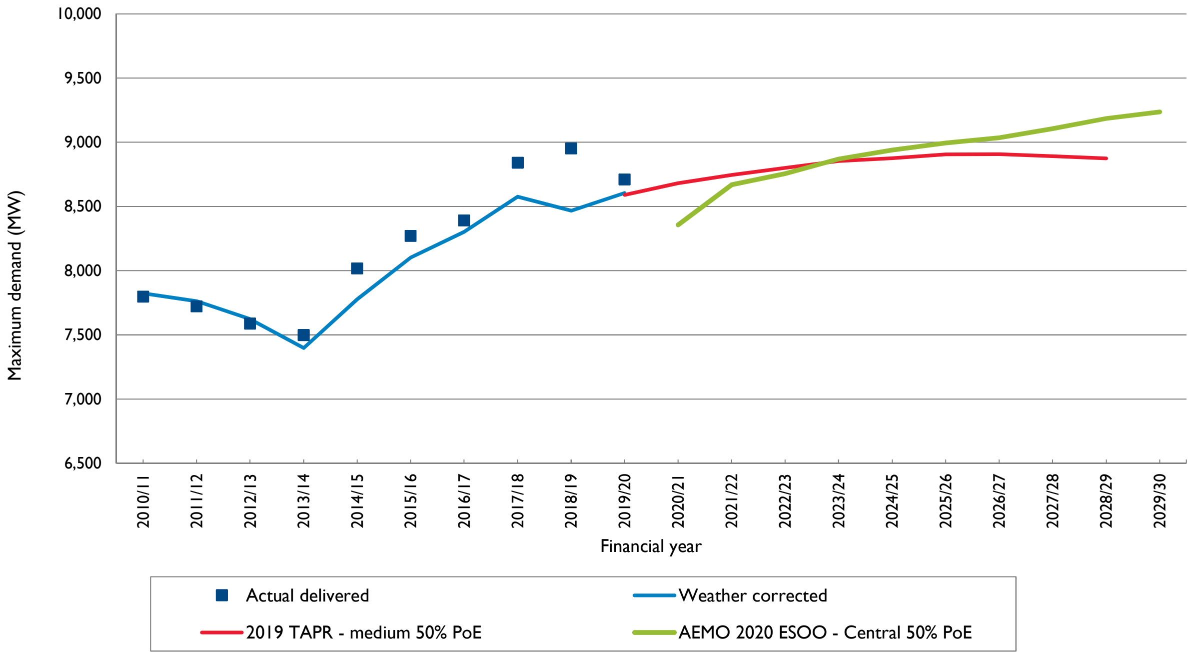
Demand and energy forecast

We have adopted AEMO's 2020 ESOO forecasts as the basis for our network planning analysis. These forecasts have been informed by a review of actual demand outcomes observed over the 2019/20 summer peak conditions. The forecasts have also included an estimate of the impact the COVID-19 pandemic could have on both peak demand and energy consumption for 2020/21. We have converted these forecasts from 'operational sent-out' to 'transmission delivered', which we consider is a better measure of the demand for transmission services as it aligns with the level of service specified in our Transmission Authority. A description of the different measures of demand and energy is provided in our TAPR[12].

As shown in Figure 5.2, the peak demand forecast under the ESOO central scenario starts below Powerlink's previous demand forecast from the 2019 TAPR. This reflects the assumed impact of COVID-19 on peak demand for the 2020/21 summer. It can be seen that the forecast quickly recovers in 2021/22 and continues to grow steadily at around 0.7% per annum over the next 10 years.

[12] 2020 Transmission Annual Planning Report, Powerlink Queensland, October 2020.

Figure 5.2: Comparison of the 2019 TAPR demand forecast with AEMO's 2020 ESOO (MW)



Notes:

(1) AEMO's 2020 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison.

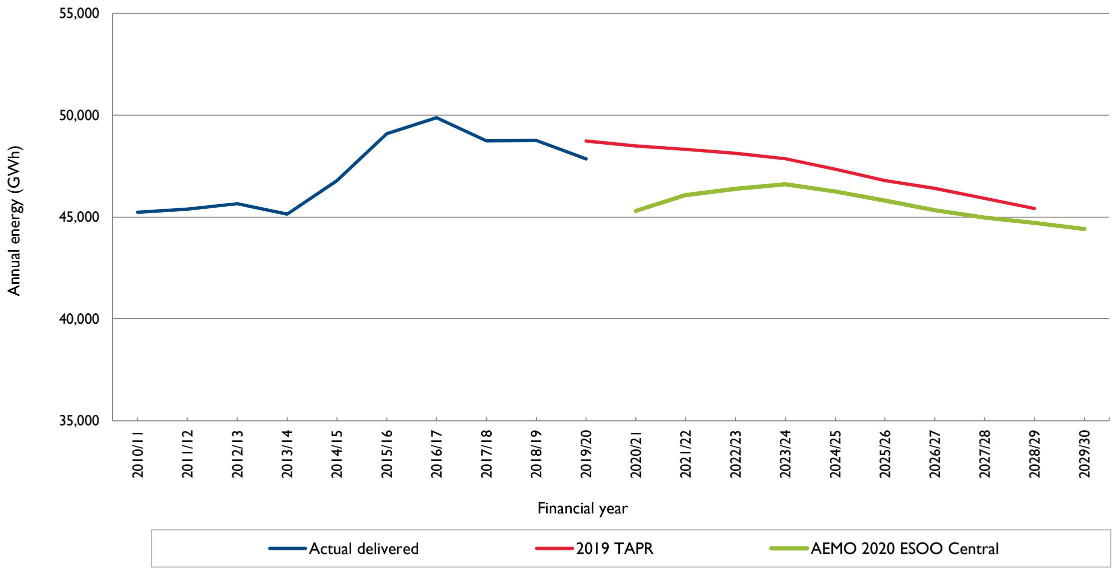
(2) AEMO's 2020 ESOO forecast has been adjusted for future uncommitted distribution connected renewables by Powerlink to incorporate the Queensland Government's target of 50% renewable energy by 2030.

Similarly, forecast annual energy consumption (refer Figure 5.3) shows a significant reduction in 2020/21 compared to the 2019 TAPR forecast, due to the assumed impact of COVID-19, before recovering over the next few years. However, in contrast to forecast peak demand, energy consumption is then expected to resume its recent declines as a result of the continued uptake of rooftop photovoltaic (PV) and other embedded energy resources. Overall energy consumption is forecast to decline at an average rate of 0.7% per annum over the next 10 years.

Noting that the 2019 ESOO and 2019 TAPR forecasts were similar to each other, there are several reasons why the demand and energy forecasts from the 2020 ESOO and 2019 TAPR are different. These mainly relate to changes and updates to the 2020 ESOO forecast from 2019, which include:

- energy efficiency measures have been recalibrated to reflect their diminishing contribution to peak demand events (i.e. saturation);
- lower retail electricity prices which tends to encourage consumption;
- higher growth in new connections; and
- electric vehicle (EV) penetration is slightly higher in the long-term.

Figure 5.3: Comparison of the 2019 TAPR energy forecast with AEMO's 2020 ESOO (GWh)



Notes:

(1) AEMO's 2020 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison.

(2) AEMO's 2020 ESOO forecast has been adjusted for future uncommitted distribution connected renewables by Powerlink to incorporate the Queensland Government's target of 50% renewable energy by 2030.

2020 Integrated System Plan (ISP)

The 2020 ISP was released in June 2020 and sets out an optimal development path for the NEM transmission grid over the next 20 years. This optimal development path includes several future ISP projects on the Powerlink transmission network, currently expected to be required during the 2030's. These future ISP projects and their currently forecast timing are:

- QNI Medium Upgrade – early 2030's;
- Central to Southern Queensland Augmentation – early 2030's;
- Gladstone Grid Reinforcement – 2030's; and
- Far North Queensland Renewable Energy Zone – 2030's.

The 2020 ISP does not include any projects declared as actionable for Powerlink that would trigger us to undertake a RIT-T assessment.

The capital expenditure forecasts in our Revenue Proposal are consistent with the 2020 ISP. Specific elements of the capital expenditure forecasts which support the 2020 ISP are:

- $14.3m for acquisition of new easements required for the QNI Medium upgrade; and
- $18.2m[13] for targeted life extension of existing transmission line assets to maintain the existing network capacity along those major transmission flow paths identified in the ISP as requiring future augmentation. This has been included in the ex-ante capital expenditure forecast instead of proposing contingent reinvestment projects, and is pending further refinement of the timing and scope of the required augmentations in future iterations of the ISP.

Asset planning criteria

Powerlink has been issued a Transmission Authority by the Queensland Government. The Transmission Authority requires Powerlink to 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 our Transmission Authority at 50MW and 600MWh.

[13] This has reduced from an initial estimate of approximately $21.0m that we advised to the RPRG in late November 2020.

Our 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. In the Proserpine area, for example, we forecast voltage stability limitations to occur which will result in interruptions to supply should a critical contingency event occur at peak demand times. These voltage stability limitations are an example of a supporting technical standard and can be mitigated by interrupting some supply to customers to remain within the standard. However, the magnitude of the potential supply interruption is less than the standards set in our Transmission Authority. In this example, the application of our Asset Planning Criteria Framework has deferred investment in network augmentation and delivered cost savings to electricity customers.

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.

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 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.

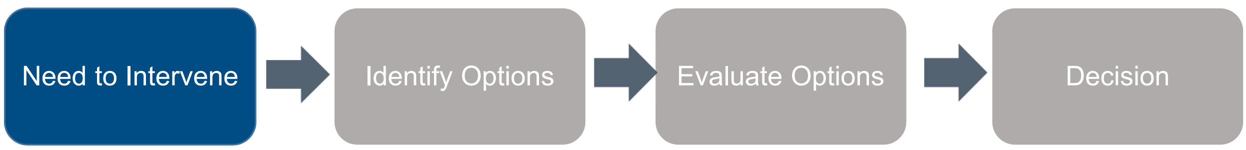
Our Asset Reinvestment Criteria Framework defines the methodology that we use to assess the need and timing for intervention on network assets to ensure that industry compliance obligations are met. The methodology aims to improve transparency and consistency within the asset reinvestment process, enabling our customers and stakeholders to better understand the criteria 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. This category of reinvestment 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 is defined when business-as-usual activities (including routine inspections, minor condition-based and corrective maintenance and operational refurbishment) no longer enable the network asset to meet prescribed standards of service due to deteriorated asset condition.

Our Asset Reinvestment Process (refer Figure 5.4) 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 5.4: Asset Reinvestment Process



Our Asset Reinvestment Criteria Framework has been developed progressively and we have engaged with our Customer Panel during the course of its development. The principles set out in this framework underpin the timing of specific reinvestment projects in our Revenue Proposal. The Asset Reinvestment Criteria Framework is provided as a supporting document to our Revenue Proposal.

5.6 Forecasts by category

5.6.1 Network load-driven expenditure

Our total forecast load-driven expenditure of $30.2m is $3.4m (13%) more than the actual/forecast expenditure in the current regulatory period.

Augmentation

As noted in Section 5.5.3 peak demand is forecast to grow modestly over the next 10 years, averaging 0.7% per annum. Based on this demand forecast we do not anticipate the need for any capital expenditure on new shared network assets to meet increases in peak demand.

Our augmentation expenditure mainly relates to our ongoing program of ground clearance rectification to remove identified encroachments to our transmission lines. This will increase our network capacity and enhance the performance of an existing asset. For this reason the expenditure is categorised as augmentation.

Connections

Based on the demand forecast we have identified the need to augment connection point transformer capacity at one bulk supply substation at Goodna Substation which supplies the Springfield area south-west of Brisbane. This area continues to experience significant residential and commercial development.

Easements

Forecast expenditure on easements is focused on the acquisition of new easements required for the QNI Medium project. While the 2020 ISP's timing for the completion of QNI Medium is around 2032 the scale of the project is such that construction would need to commence by the late 2020s. This requires that line easements be acquired during the 2023-27 regulatory period.

A key driver of this timing is to ensure we can undertake meaningful engagement with landholders who may be impacted by this major transmission line investment. We consider it is important that this work be commenced early in the 2023-27 regulatory period to enable this to occur. These activities are beyond the preparatory works identified by AEMO in its 2020 ISP, which we are required to report on by 30 June 2021.

5.6.2 Network non load-driven expenditure

Network non load-driven expenditure is the most significant contributor to our forecast capital expenditure for the 2023-27 regulatory period. Our forecast expenditure of $726.1m is $37.5m (4.9%) lower than the actual/forecast expenditure in the current regulatory period. The majority of this is in the reinvestment category.

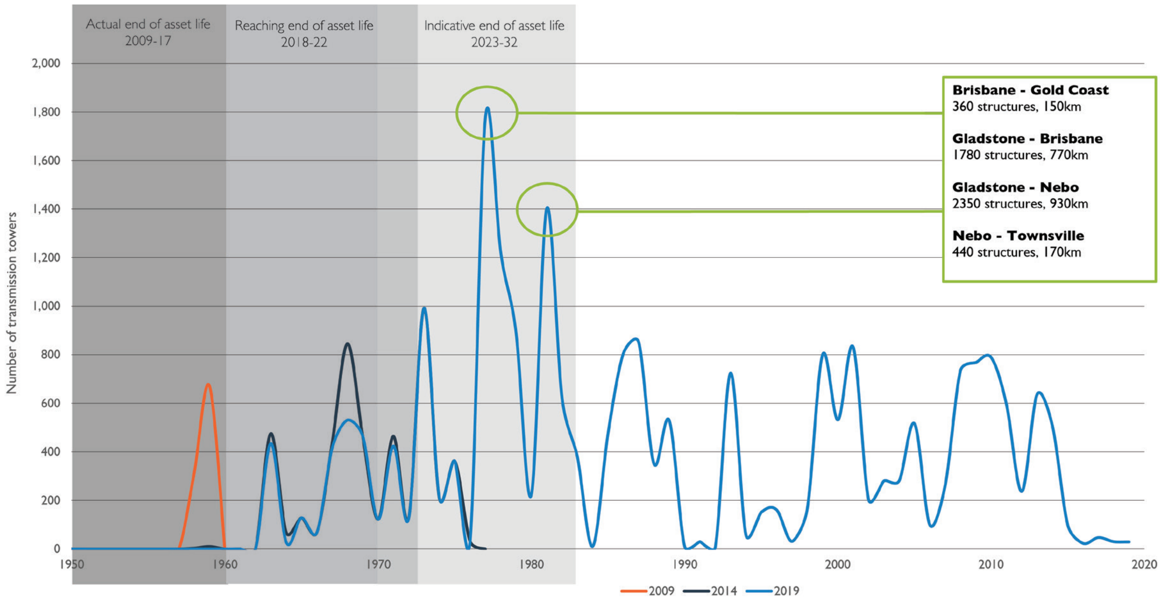
Forecast reinvestment expenditure for the 2023-27 regulatory period is slightly lower than actual/forecast reinvestment in the current regulatory period. While reinvestment expenditure is not as lumpy as augmentation expenditure, which is required to meet increases in demand, the reinvestment expenditure profile will tend to reflect the earlier, initial investment profile. That is, it is not recurrent in the same way that operating expenditure is largely recurrent. Given the transmission network in Queensland developed rapidly from the late 1960's to early 1980's we expect to see a growing trend in reinvestment expenditure needs into future regulatory periods.

A more detailed description of how the Hybrid+ forecasting methodology has been applied to these categories of capital expenditure is provided in Appendix 5.04 Non Load-Driven Network Capex Forecasting Methodology.

Transmission towers reinvestment

A main driver of our reinvestment program is our steel lattice transmission towers. This reflects the age profile of the towers. Significant investment occurred to interconnect the Queensland network from the early 1970s to 1980s, with nearly 20% of our current fleet of transmission towers constructed between 1977 and 1981. This is shown in Figure 5.5 (where the different coloured lines show the asset age profile as it was at those earlier times). A large number of these towers are now approaching their end of life.

Figure 5.5: Transmission towers age profile



As these steel lattice towers age, the level of corrosion and deterioration reaches a point where actions beyond normal maintenance will be required.

Given the number of towers approaching their end of life, we expect there will be a need to undertake an extended investment program over several regulatory periods. As the rate of corrosion and deterioration is not uniform, replacement decisions will be based on an assessment of asset condition. This is more prudent and efficient than simply basing these decisions on individual asset age.

While individual asset age is not a driver of reinvestment decisions, the trend in the age across the fleet of assets can indicate whether the level of reinvestment is likely to be higher or lower going forward. Between 2015/16 and 2018/19 the average age of our fleet of transmission towers increased by 2.7 years. Based on the level of reinvestment being proposed we expect the average age at the end of the 2023-27 regulatory period to have increased by a further five years. This reflects our approach to transmission line life extension works which targets those sections of a transmission line where local environmental conditions cause faster rates of corrosion while leaving the slower deteriorating sections for later reinvestment. In this way we aim to exhaust as much life as possible across the entire asset before committing to a full replacement.

Secondary systems and telecommunications reinvestment

Another significant driver of reinvestment expenditure is our fleet of digital secondary systems and telecommunications assets. The adoption of digital technologies in protection and control systems has brought a number of benefits to both Powerlink and electricity customers, including:

- multiple functions within a single device which reduces the total cost to provide the full range of functions required to safely and securely operate the power system;
- self-monitoring which signals when a device has failed in service and minimises the risk of mal-operation of a previously failed device that went undetected; and
- remote interrogation which allows power system faults to be rapidly analysed and diagnosed. This can pre-empt or even avoid the cost of calling out crews to attend remote substations and speed the restoration of supply to customers.

The nature of these digital technologies is such that obsolescence and lack of vendor support for discontinued devices diminishes these benefits over time. Once a like-for-like replacement is no longer available, then unplanned or reactive replacement is operationally and technically more complex due to issues such as:

- interoperability and protocol difference between other devices on site, and with remote ends (if applicable);
- development and testing of new configurations and settings;
- physical differences with the mounting and installation, including cabling and connectivity; and
- legislative requirements for professional engineering certification[14].

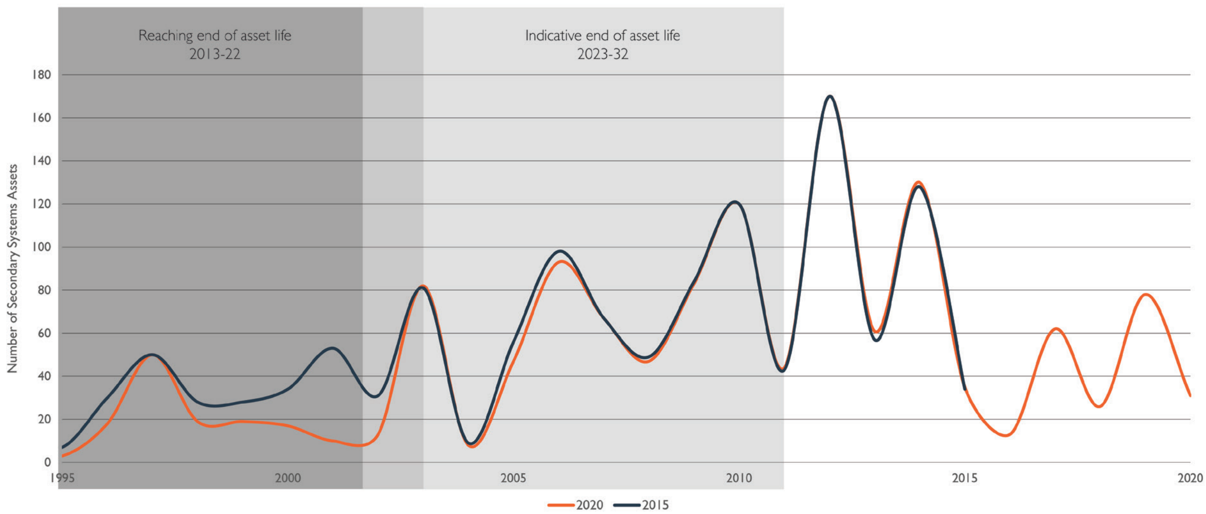
[14] *Professional Engineers Act 2002* (Queensland), s115.

The implication of this is that return to service times will extend considerably for these unsupported devices.

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 could overwhelm our capacity to undertake corrective maintenance or replacement projects and potentially leave us in breach of the Rules[15], the AEMO standards[16] and its jurisdictional obligations[17].

For these reasons, we consider it is important to not allow a significant volume of obsolete and unsupported devices to remain in service on the network. The typical product lifespan for our secondary systems assets is around 20 years. With significant expansion of our network during the 2000s in response to growth in customer demand there will be an increasing volume of secondary systems assets requiring reinvestment in the 2023-27 and 2028-32 regulatory periods. This is shown in Figure 5.6.

Figure 5.6: Secondary systems age profile



Meeting power system performance standards
We have also included a new System Services category in our capital expenditure forecast. This category is driven by the need to meet power system performance standards, including voltage control, inertia and system strength. Our forecast capital expenditure for this category is similar to forecast capital expenditure in the current regulatory period.

5.6.3 Non-network expenditure

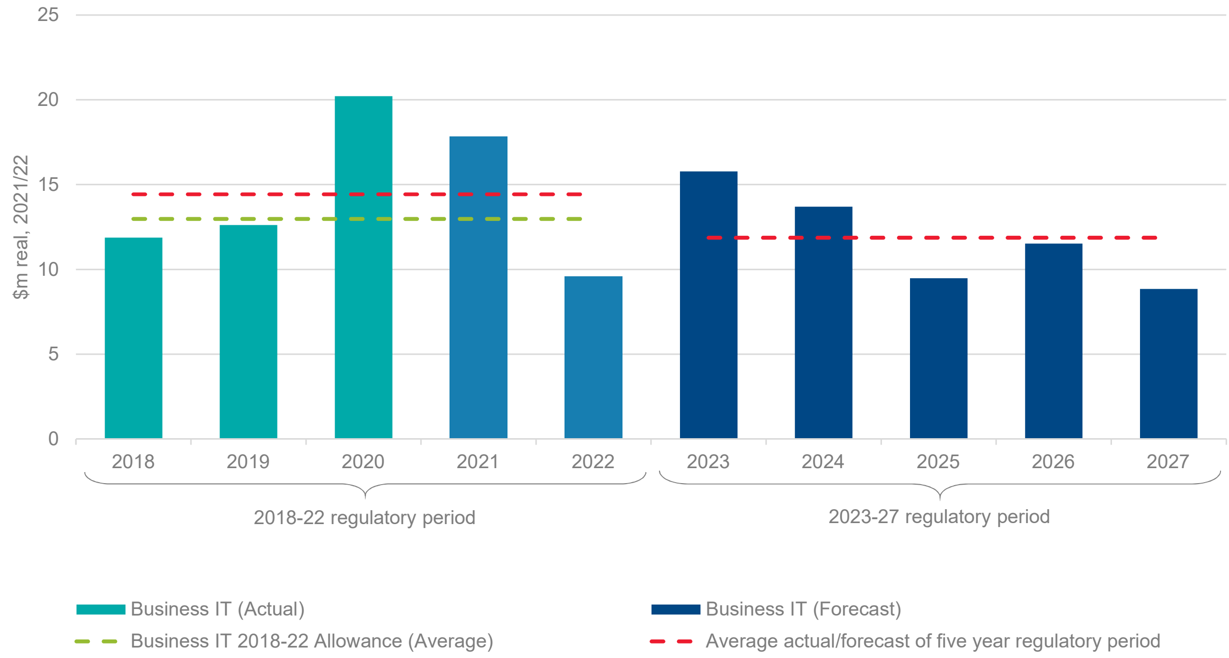
Our total forecast non-network capital expenditure of $107.7m is $6.7m (6.7%) more than the actual/forecast expenditure for the current regulatory period.

We forecast reduced expenditure in the Business IT category for the 2023-27 regulatory period compared to the current regulatory period. Approximately $7.0m of capital expenditure for renewal of our Enterprise Resource Planning (ERP) and Geographical Information System (GIS) platforms has been brought forward to provide more efficient integration with other initiatives within the current regulatory period. This has reduced the forecast capital expenditure for Business IT in the 2023-27 regulatory period. We have included a copy of our IT Plan, which explains our IT approach, in Appendix 5.05 IT Plan 2023-27.

Our forecast capital expenditure for Business IT for the 2023-27 regulatory period, along with our actual/forecast expenditure for current regulatory period is shown in Figure 5.7.

15 National Electricity Rules, schedule 5.1, clause S5.1.2.1(d), clause S5.1.9(c).
16 Power System Operating Procedure (SO_OP_3715), AEMO and Power System Security Guidelines, AEMO.
17 *Electricity Act 1994* (Queensland), s34(1)(a) and Powerlink's Transmission Authority T01/98.

Figure 5.7: Business IT capital expenditure ($m real, 2021/22)



The vast majority (> 95%) of our forecast capital expenditure for Business IT is either recurrent expenditure, being periodic replacement or cyclical upgrade with less than a five year cycle, or non-recurrent expenditure to maintain the capability of our systems, being periodic renewal with longer than a five year cycle. A summary of our forecast capital expenditure for Business IT is shown in Table 5.9.

Table 5.9: Business IT capital expenditure by investment driver ($m real, 2021/22)

Driver	Forecast capital expenditure	Brief definition
Non-recurrent		
Compliance and Risk	2.7	Expenditure to comply with new or changed regulatory obligations or to meet new or emerging risks, such as increasing cyber security threats.
Maintain capability	27.5	Periodic expenditure longer than a five year cycle such as upgrade or renewal of major corporate systems.
New capability	-	Expenditure to acquire new or expanded capability such as automating an existing manual task, where this is the primary justification for the expenditure.
Recurrent	29.2	Periodic expenditure less than a five year cycle such as end-user device replacement or upgrades to Windows and Office.
Total	**59.3**	

The IT Plan forecasts investment of $27.5m, around 46% of the total Business IT capital expenditure, on the replacement and renewal of legacy systems to maintain capability. This investment will contribute to improving our operating expenditure productivity in the following ways:

- support improvements in process efficiency when we replace legacy systems with contemporary ones that provide for more seamless data integration and management of process flows; and
- the total cost of IT system ownership will reduce through consolidation of applications, databases, platforms etc. and the use of standardised systems with fewer customisations.

Within the overall non-network capital expenditure forecast, our reduced IT spend is offset by the deferral of our proposed office refit project, which was included in our forecast for the current regulatory period[18]. We now plan to undertake these works during the 2023-27 regulatory period. Our analysis shows that a major refit of our office facilities will provide for more efficient use of the available space. This will allow us to consolidate staff accommodation and sell the premises that are no longer required, which would result in ongoing cost savings for customers. This may need to be further optimised as we incorporate the learnings from the COVID-19 pandemic into efficient work practices and office arrangements.

Our approach to forecasting non-network capital expenditure is provided in Appendix 5.06 Guide to Non-Network Capital Expenditure.

5.7 Contingent projects

Contingent projects are investments that may be required 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[19]. 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[20].

Generally, contingent projects are significant network augmentation projects[21] 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 the following three categories of drivers.

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.

Integrated System Plan

AEMO's 2020 ISP identifies significant network augmentations that could deliver net market benefits and are part of the optimal development path across the NEM. While the expected timing for these projects is currently beyond the 2023-27 regulatory period the ISP is reviewed and updated on a two-yearly cycle. Given the rapid changes occurring in the electricity sector with the retirement of ageing coal-fired generation and rapid uptake of IBR it is possible that one or more of these projects could be required during the 2023-27 regulatory period.

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[22]. To avoid the potential for conflicting trigger conditions between our proposed contingent projects and actionable ISP projects, we have not proposed any contingent projects that are already within the ambit of the 2020 ISP. This is a change from our draft Revenue Proposal where we considered it appropriate to include these ISP projects as contingent projects. This change is in direct response to feedback received on our draft Revenue Proposal from AER staff.

While we have not proposed any existing ISP identified projects as contingent projects we have included information regarding our current estimates of the costs of the ISP projects, based on our understanding of the scope of works at this time. This is to aid transparency around the process and ensure customers are fully informed. Future ISP projects and their indicative timing and estimated costs are summarised in Table 5.10.

18 We intend to return the revenue attributable to the capital expenditure allowance for this project to customers in 2021/22
19 National Electricity Rules, clause 6A.8.1.
20 National Electricity Rules, clause 6A.8.2(a)-(f).
21 For us, this will be approximately $34.5m in the 2023-27 regulatory period.
22 National Electricity Rules, clause 6A.8.2(a)(2).

Table 5.10: Future ISP projects ($m real, 2021/22)

Project name	2020 ISP indicative timing	Indicative capital cost
QNI Medium Upgrade	2032/33	582 (Queensland component only)
Far North Queensland Renewable Energy Zone	2030's	261
Gladstone Grid Reinforcement	2030's	298
Central to Southern Queensland Reinforcement	Early-2030's	353

Contingent reinvestment

In our draft Revenue Proposal we proposed to apply the contingent projects framework to network reinvestment projects where the timing of the condition-based reinvestment trigger remains uncertain, or where the expected solution to the condition trigger is not sufficiently certain.

Our proposal for contingent reinvestment projects related to those transmission line assets on major transmission flow paths aligned with ISP identified needs. The ISP has identified the potential future need for significant additional capacity along those major transmission flow paths and the optimal asset reinvestment strategy can depend on the timing and scale of those ISP identified needs. However, the scale and timing of those future needs is highly dependent on the rate of development and location of new renewable energy sources, and the timing of the retirement of existing thermal generators. While the eventual need for this capacity may be highly likely, the optimal timing can be expected to shift between successive iterations of the ISP, as updated information becomes available.

The objective of our contingent reinvestment proposal has been to ensure customers do not pay for the forecast cost of reinvestment projects within the capital expenditure and revenue allowances set by the AER upfront, where the quantum and timing of those costs is still uncertain. It also protects Powerlink against the need to undertake major reinvestment expenditure that also provides additional network capacity to meet needs identified in the ISP. This could occur where the condition-based trigger to reinvest arises before an ISP project becomes actionable, noting that it is only when an ISP project becomes actionable that it is deemed under the Rules to become a contingent project.

We undertook regular engagement with stakeholders on our contingent reinvestment proposal in advance of our draft Revenue Proposal, including with our Revenue Proposal Reference Group (RPRG), the AER, and the AER's CCP23. While the RPRG and the AER's CCP23 were supportive of the concept as a way to balance risks between consumers and Powerlink, their feedback on our draft Revenue Proposal was to not support using the existing contingent project framework for this purpose. Through our engagement the AER raised the following concerns with our proposal:

- it reduces the incentive properties of the ex-ante revenue determination framework;
- an asset condition trigger cannot be objectively verified, as required by the Rules; and
- an asset condition trigger is not an exogenous event, beyond the ability of a TNSP to influence.

Based on this feedback and in the interests of lodging a Revenue Proposal that is capable of acceptance by the AER, we are no longer proposing contingent reinvestment projects in our Revenue Proposal. Notwithstanding this decision, we consider there is still a need for the regulatory framework to accommodate some form of contingent reinvestment trigger and we may look to pursue this further outside of our Revenue Proposal.

5.7.1 Proposed contingent projects

Our proposed contingent projects and their indicative costs are summarised in Table 5.11. Appendix 5.07 Contingent Projects provides further detail on our single proposed contingent project and its triggers. Should any of these triggers occur, we will undertake the required regulatory processes, including engagement with the AER.

Table 5.11: Contingent projects ($m real, 2021/22)

Project name	Type of trigger	Indicative capital cost
Central to North Queensland Reinforcement	Additional customer demand(1)	52.3
Total indicative cost		**52.3**

(1) This could include additional customer demand from Mount Isa should the Copperstring project proceed.

Central to North Queensland Reinforcement

The Central West and North Queensland zones are areas where significant increases in the demand and energy are plausible during the 2023-27 regulatory period. The most significant sources for this increased load include, but may not be limited to:

- development of the Copperstring transmission project to connect Mt Isa and the North West Minerals province to the NEM; and
- development of large-scale coal mines in the Galilee Basin and associated rail and port infrastructure.

Power transfer capability into northern Queensland is limited by thermal ratings or voltage stability limitations, depending on prevailing weather conditions and scheduled generation. Thermal limitations may occur on the Bouldercombe to Broadsound 275kV line following a critical contingency of a Stanwell to Broadsound 275kV circuit. Voltage stability limitations may occur following the trip of the Townsville gas turbine or following a contingency of a Stanwell to Broadsound 275kV circuit.

As demand increases in northern Queensland transmission congestion may occur, requiring northern Queensland generators to be constrained on. As generation costs are higher in northern Queensland due to reliance on liquid fuels, it may be economic to advance the timing of augmentation to deliver positive net market benefits. The additional load in northern Queensland that would justify the network augmentation in preference to continued network support cost is between 250MW and 380MW. The lower bound assumes the out-of-merit-order generation is predominantly liquid fuelled at approximately $450/MWh, while the upper bound assumes up to 240MW of gas-fired generation is available at approximately $60/MWh.

This proposed contingent project comprises the stringing of the second circuit of an existing double circuit line between Stanwell and Broadsound that currently has only one side strung. The proposed contingent project is estimated to cost $52.3m.

We consider that the project should be accepted as a contingent project for the 2023-27 regulatory period due to the uncertainty about the trigger event occurring and the scope and cost of the project required to maintain reliability of supply.

5.8 Network support

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[23]. We have also published a Network Support Contracting Framework as a general guide to assist potential non-network solution providers understand the key contracting principles that underpin our network support agreements[24].

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 enhanced with the introduction of inertia services and system strength services to accommodate increasing levels of IBR and the reduced level of synchronous generation.

In its 2020 System Strength and Inertia Report, AEMO concluded that fault level and inertia shortfalls are not yet considered likely for Queensland in the next five years, but shortfall risks are increasing[25]. Changes to the operating patterns of large synchronous generators could result in either or both types of shortfall declared during the 2023-27 regulatory period. 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.

We have also identified the potential for future network support arrangements with generators and large loads to form part of an upgraded scheme to extend the power transfer limits between Central Queensland and Southern Queensland[26]. These costs, if they are able to provide a net market benefit, form an efficient use of operating expenditure in place of capital expenditure – a capex/opex trade-off.

23 Non-Network Solutions, Powerlink, https://www.powerlink.com.au/non-network-solutions.
24 *Ibid.*
25 2020 System Strength and Inertia Report, Australian Energy Market Operators, December 2020, page 24.
26 National Electricity Rules, schedule 6A.1, clause S6A.1.1(8)

5.9 Deliverability of future expenditure

We have a proven ability to deliver capital projects to meet the needs of Queensland customers for a safe, secure, reliable and cost-effective supply of electricity. Our forecast capital expenditure for the 2023-27 regulatory period is approximately 3% lower than the actual/forecast expenditure for the current regulatory period. To ensure we have the capability to deliver this level of work, we will continue to use the proven business processes identified in our 2018-22 Revenue Proposal and take the following steps to enhance these:

- ***Portfolio risk management***: We have continued the development of our portfolio risk management approach with the deployment of a Portfolio Risk System (PRS). The PRS performs asset data analytics to support more structured asset reinvestment planning across various asset classes. This supports the optimisation in planning our portfolio of projects to manage overall risk across the network.
- ***Delivery Optimisation Framework***: We recognise that delivery of a significant program of capital expenditure projects to mitigate network asset risks is subject to multiple constraints. The Delivery Optimisation Framework (DOF) provides a structured mechanism to coordinate the delivery of our portfolio of projects throughout their delivery lifecycle. It allows for the early identification and resolution of resource constraints or conflicts to maximise the deliverability across the whole portfolio.
- ***Substation and line refit panel arrangements:*** During the current regulatory period we have worked collaboratively with our contractors to better structure work packages to accommodate the many site-specific constraints that exist with brownfield reinvestment works. While this can require additional effort in the early stages of project delivery it can significantly reduce the risks of delays and rework during the site delivery and commissioning phases.
- ***Relocatable switching bay:*** We have recently procured a mobile high voltage switching bay that will facilitate project delivery in circumstances where network outages are difficult to secure. It provides a temporary bypass to allow for equipment replacement within a switching bay without the need for an extended outage of the element connected to that switching bay.

5.10 Summary

We have developed our forecast capital expenditure for the 2023-27 regulatory period consistent with the requirements of the Rules and our Expenditure Forecasting Methodology (refer to Appendix 5.03 Expenditure Forecasting Methodology). Our Hybrid+ approach integrates top-down and bottom-up approaches, with project-specific justification provided for over 70% of our forecast capital expenditure.

Our total forecast capital expenditure for the 2023-27 regulatory period is $863.9m, which is $27.4m (3.1%) lower than the actual/forecast expenditure for the current regulatory period. The majority of this forecast ($726.1m or 84%) is non load-driven network expenditure. We have proposed one contingent project that is not in our ex-ante capital expenditure forecast.

6. Forecast Operating Expenditure

6.1 Introduction

This chapter presents Powerlink's forecast operating expenditure for each year of the 2023-27 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.

Note that references in this chapter to total operating expenditure reflect underlying operating expenditure, unless otherwise stated. For clarification, our underlying operating expenditure excludes movements in provisions, Network Capability Incentive Parameter Action Plan (NCIPAP) project costs which are part of the Service Target Performance Incentive Scheme (STPIS), debt raising and network support costs. This is explained further in Section 6.4.1.

Key highlights:

- We have targeted no real growth in total operating expenditure over the 2023-27 regulatory period. This target is relative to our underlying actual/forecast operating expenditure over the current 2018-22 regulatory period:
  - Customer feedback on productivity, affordability and the impacts of the current economic climate have been central to this decision.
  - To meet this target, we have proposed a productivity factor of 0.5% per annum, which is higher than the industry benchmark average of 0.3% per annum[1], and no step changes.
- Our total operating expenditure forecast for the 2023-27 regulatory period is $1,029.4m ($1,046.4m with debt raising costs included). This represents:
  - no change from underlying actual/forecast operating expenditure for the 2018-22 regulatory period; and
  - a $7.9m (or 0.8%) increase from actual/forecast operating expenditure for the 2018-22 regulatory period with debt raising costs included.
- As a result of our no real growth approach, which includes no step changes, we forecast potentially up to $26.1m of cost increases (e.g. insurance premiums, cyber security requirements) over the 2023-27 regulatory period that we may need to absorb over and above our operating expenditure forecast.
- We engaged HoustonKemp to undertake an independent assessment of the efficiency of our proposed base year expenditure (2018/19). HoustonKemp's analysis suggests that our 2018/19 revealed operating expenditure is not materially inefficient[2].
- Our forecasts are based on the Australian Energy Regulator's (AER's) base-step-trend methodology. We have also developed a category-specific forecast for the Australian Energy Market Commission (AEMC) Levy.

6.2 Regulatory requirements

The National Electricity Rules (the Rules)[3] require that we submit our forecast operating expenditure for the 2023-27 regulatory period.

Our Expenditure Forecasting Methodology (refer to Appendix 5.03) sets out our approach to forecasting operating expenditure and is designed to produce operating expenditure forecasts that satisfy the requirements of the Rules[4]. 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. We have also had regard to the AER's 2013 Expenditure Forecast Assessment Guideline for Electricity Transmission.

6.2.1 Operating expenditure objectives

We consider that our forecast operating expenditure achieves the operating expenditure objectives set out in clause 6A.6.6(a) of the Rules. This is summarised in Table 6.1. We also consider that our forecast reflects the operating expenditure criteria and factors set out in clause 6A.6.6(c) and 6A.6.6(e), as discussed in detail in Appendix 5.01 Operating and Capital Expenditure Criteria and Factors.

[1] Economic Benchmarking Results for the Australian Energy Regulator's 2020 TNSP Annual Benchmarking Report, Economic Insights, October 2020, page 62.

[2] This reflects terminology used by the AER in their Expenditure Forecast Assessment Guideline for Electricity Transmission, November 2013, page 22 and recent determinations, as explained by HoustonKemp in Section 2.2 of their report (refer to Appendix 4.01).

[3] National Electricity Rules, clause 6A.6.6 and schedule 6A.1, clause 6A.1.2.

[4] National Electricity Rules, clause 6A.6.6(b).

Table 6.1: 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.	Demand is forecast to be relatively constant across our network over the 2023-27 regulatory period, in line with minimal growth seen over the 2018-22 regulatory period. Our no real growth approach to operating expenditure reflects a prudent and realistic cost forecast to operate and maintain our transmission network assets and the functions that support the delivery of safe, secure and reliable outcomes.
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* and as a registered Transmission Network Service Provider (TNSP) in the National Electricity Market (NEM). As a company we are also subject to various other environmental, cultural heritage, planning approval, Workplace Health & Safety, financial and other regulations. Our compliance with these regulatory obligations and requirements is encompassed in our Asset Management Framework and associated policies and procedures, which provide the foundation for our operating and maintenance activities. These are provided as supporting documents to our Revenue Proposal. New regulatory obligations or requirements have also been assessed to determine the potential effect on forecast operating expenditure in the 2023-27 regulatory period.
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 forecasts include 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 Revenue Proposal to ensure network assets deliver the required safety, reliability, availability and quality of supply in the most prudent and efficient manner.

6.3 Operating expenditure categories

We have retained the same broad categories of operating expenditure from the current 2018-22 regulatory period, as outlined in Table 6.2.

Table 6.2: Operating expenditure categories

Operating expenditure category	Definition	Prescribed transmission service
Controllable operating expenditure		
Direct operating and maintenance expenditure		
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 land.	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 represent asset support functions in the field. It also includes non-field functions supporting maintenance activities for the operate/maintain phase of the asset life cycle such as maintenance strategy development, performance management and maintenance auditing. This category also includes local government rates charges, water charges, electricity charges and charges for permits 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 Australian Energy Market Operator (AEMO) requirements.	Exit, entry, TUOS and common services
Other controllable expenditure		
Asset management support	Activities required to support the strategic development and ongoing asset management of the network. There are four major subelements: 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 both the cost of premiums to maintain commercial insurance coverage and self-insurance costs to provide cover for minor losses that cannot be insured.	Common services
Network support	Refers to costs associated with non-network solutions used by Powerlink as a cost-effective alternative to network investment.	TUOS services
AEMC Levy	Since 2014/15, the *Electricity Act 1994* has required electricity transmission networks in Queensland to pay a share of the State's cost to fund the AEMC.	Common services
Debt raising costs	Costs incurred by an entity over and above the debt margin.	Common services

6.4 Forecast operating expenditure overview

This section presents our forecast operating expenditure for the 2023-27 regulatory period and explains our target of no real growth.

6.4.1 No real growth target

We have heard customer feedback on business productivity, affordability and the impacts of the current economic climate. Based on this feedback and our goal to have a Revenue Proposal that is capable of acceptance by our customers, the AER and Powerlink at the time we lodge our Revenue Proposal, we have committed to pursue a no real growth in operating expenditure. To be clear, this represents a stretch target for our business and is a floor below which we do not consider it would be prudent or efficient for us to operate in the circumstances.

This target is relative to our underlying actual/forecast operating expenditure of $1,029.4m for the 2018-22 regulatory period. We have made several adjustments to our actual/forecast operating expenditure for the 2018-22 regulatory period to derive our total underlying operating expenditure for the period[5], which are described in Table 6.3. These changes were discussed with the AER and customers prior to lodging our Revenue Proposal.

Table 6.3: No real growth target calculation ($m real, 2021/22)

Adjustment	Description and explanation for adjustment	Total $
Actual/forecast operating expenditure 2018-22 regulatory period		1,038.5
Remove movements in provisions	Movements in provisions are adjustments that occur on an annual basis to reflect an estimate of the amount that would be required to settle a future liability (e.g. employee leave). Movements in provisions are removed from our target consistent with the AER's 2013 Expenditure Forecast Assessment Guideline[(1)].	(2.6)
Remove network support costs	Network support costs are non-recurrent and are managed through the cost-pass through mechanism for network support in the Rules. Therefore, they do not represent underlying expenditure.	(3.1)
Remove NCIPAP project costs	NCIPAP projects occur under the STPIS and are removed from operating expenditure targets consistent with clause 5.2(r)(1) of version 5 of the STPIS.	(0.4)
Remove debt raising costs	The AER sets debt raising cost allowances by way of a benchmark methodology. As a result, debt raising costs are not included as part of our no real growth target for operating expenditure.	(2.9)
Underlying actual/forecast operating expenditure for the 2018-22 regulatory period		**1,029.4**

(1) Expenditure Forecast Assessment Guideline for Electricity Transmission, Australian Energy Regulator, November 2013, page 22.

To meet our target of no real growth and ensure we continue to operate in a prudent and efficient manner, we propose:

- a productivity improvement target of 0.5% per annum. This is higher than the industry benchmark average of 0.3% per annum[6];
- not to pursue any operating expenditure step changes (refer Section 6.6.3); and
- to absorb potential operating expenditure increases (e.g. due to new regulatory/legislative obligations and reasonable increased insurance premiums), or rely on cost pass through arrangements in the event of material cost increases within period (refer Chapter 12 Pass Through Events).

The adoption of this approach to establish our operating expenditure forecast was a significant shift for our business during the development of our Revenue Proposal and it will be a challenge for us to meet this target. However, on balance, we considered that we should rise to this challenge in the interests of customers and to continue to drive the business hard to find further efficiencies and productivity improvements to become a world-class transmission service provider.

5 We have applied similar adjustments to our 2018/19 base year operating expenditure, where these costs have been incurred in that year (refer Section 6.6.1).

6 Economic Benchmarking Results for the Australian Energy Regulator's 2020 TNSP Annual Benchmarking Report, Economic Insights, October 2020, page 62.

We proposed the no real growth target as part of our draft Revenue Proposal in September 2020 (refer Chapter 3 Customer Engagement). Our Customer Panel, the AER's Consumer Challenge Panel (CCP23) and broader customers and stakeholders expressed support for the ambition and effort behind this target and our decision not to pursue any step changes.

Some customers and stakeholders also acknowledged the risks of pursuing a no real growth target, such as the potential to overspend our allowance in the 2023-27 regulatory period, and requested further detail in particular about how we intend to meet this target. Others expressed caution about whether Powerlink was pushing itself too far in setting such a challenging target. We discuss potential productivity initiatives in Section 6.6.2.

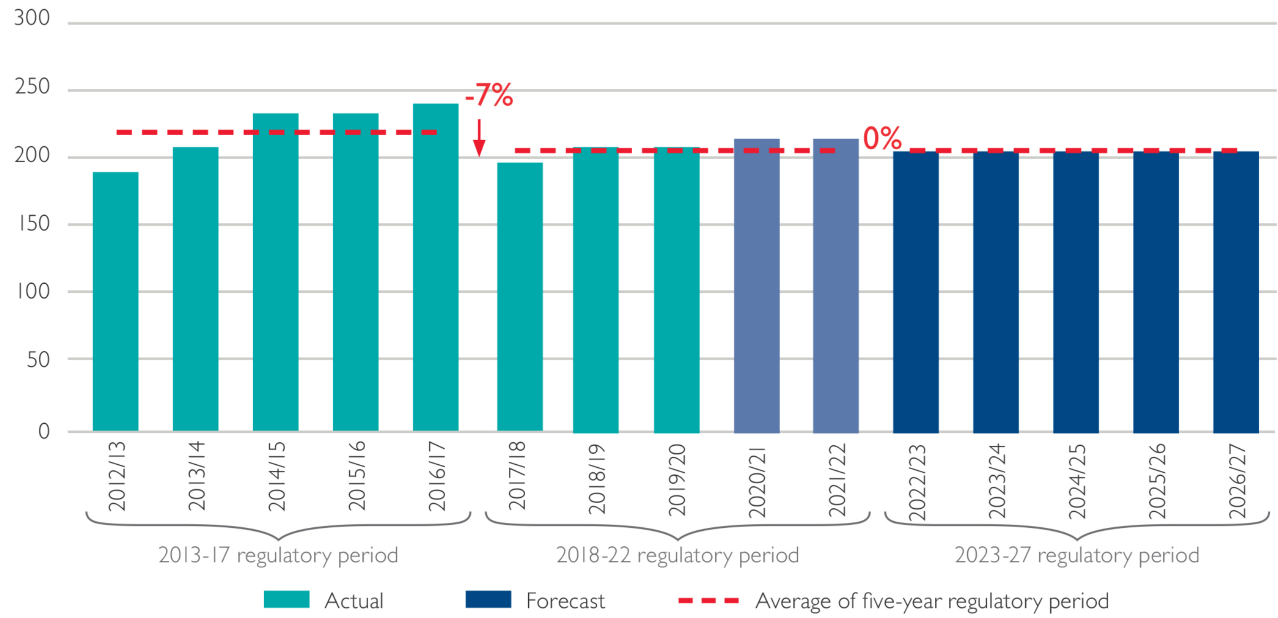
We recognise there are a number of potential externally driven increases in operating expenditure requirements expected over the 2023-27 regulatory period that may impact our ability to meet our target of no real growth. These include potential cost increases in insurance, elevated cyber security requirements and new outage management complexities to maintain system strength as additional Inverter-Based Resources (IBR) are commissioned.

If for any reason we cannot continue to deliver safe, secure and reliable services within our target forecast, we will overspend our allowance. We recognise this is a risk for Powerlink, our customers and shareholders, which is why we will only consider this course of action as a last resort and only to the extent necessary to meet our obligations.

6.4.2 Total forecast operating expenditure

Our total forecast operating expenditure for the 2023-27 regulatory period, along with our actual/forecast expenditure for the previous and current regulatory periods, is shown in Figure 6.1.

Figure 6.1: Total actual/forecast operating expenditure ($m real, 2021/22)(1)



(1) Reflects underlying operating expenditure, excluding movements in provisions, debt raising, network support and NCIPAP costs.

Our total forecast operating expenditure for the 2023-27 regulatory period is $1,029.4m. This represents $0 (no real growth) from underlying actual/forecast operating expenditure in the 2018-22 regulatory period.

With debt raising costs included, our total forecast operating expenditure is $1,046.4m, a $7.9m (0.8%) increase from actual/forecast operating expenditure in the 2018-22 regulatory period.

To derive this forecast, we have applied the AER's base-step-trend approach, as follows:

Determine an efficient base year from which to forecast operating expenditure: we have proposed 2018/19 as our efficient base year. We have reviewed our expenditure in this year on a category basis, have had the efficiency of this base year independently assessed and made relevant adjustments (refer Section 6.6.1). Using our efficient base year, we have estimated our operating expenditure in the final year of the current 2018-22 regulatory period (refer to Appendix 6.01 Forecast Operating Expenditure Methodology and Model).

Establish an annual rate of change to trend forecast operating expenditure: we applied an average annual total rate of change of 0.3% to our estimated final year. Our application of the rate of change elements is discussed further in Section 6.6.2 and broadly reflects:

- minor output growth averaging 0.3% per annum, primarily due to forecast growth in energy throughput early in the 2023-27 regulatory period on the Queensland/New South Wales Interconnector (QNI);
- estimates of real price growth for labour and materials averaging 0.5% per annum based on independent expert opinion and consistent with the AER's approach in recent regulatory decisions; and
- real productivity growth of 0.5% per annum, which is above the latest industry benchmark average of 0.3%[7].

Assess and propose step changes in operating expenditure: we do not propose any step changes (refer Section 6.6.3).

The combination of real productivity growth above the industry average and no proposed step changes reflects our commitment to customers for no real growth in operating expenditure.

We have then added non-controllable other operating expenditure forecasts which have been prepared on a category-specific basis. These forecasts are for the AEMC Levy (refer Section 6.7.2) and debt raising costs (refer Section 6.7.4). We have proposed a $0 network support allowance (refer Section 6.7.3).

Our forecast expenditure by category is shown in Table 6.4.

Table 6.4: Forecast operating expenditure by category ($m real, 2021/22)

Operating expenditure category	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Controllable operating expenditure						
Direct operating and maintenance expenditure						
Field maintenance	67.2	68.0	67.8	68.0	68.2	**339.1**
Operational refurbishment	38.4	38.9	38.8	38.9	39.0	**194.1**
Maintenance support	14.3	14.4	14.4	14.4	14.5	**72.0**
Network operations	16.1	16.3	16.3	16.3	16.4	**81.5**
Other controllable expenditure						
Asset management support	26.2	26.5	26.4	26.5	26.6	**132.2**
Corporate support	27.2	27.5	27.4	27.6	27.6	**137.3**
Total controllable operating expenditure	**189.4**	**191.7**	**191.1**	**191.8**	**192.2**	**956.2**
Non-controllable operating expenditure						
Other operating expenditure						
Insurance premiums	7.0	7.1	7.1	7.1	7.1	**35.6**
Self-insurance	1.6	1.6	1.6	1.6	1.6	**8.0**
AEMC Levy	5.9	5.9	5.9	6.0	6.0	**29.7**
Network support	0.0	0.0	0.0	0.0	0.0	**0.0**
Debt raising costs	3.5	3.5	3.4	3.3	3.2	**17.0**
Total non-controllable operating expenditure	**18.1**	**18.1**	**18.1**	**18.0**	**18.0**	**90.2**
Total operating expenditure	**207.4**	**209.8**	**209.2**	**209.9**	**210.1**	**1,046.4**
Total operating expenditure (excluding debt raising costs)	203.9	206.3	205.8	206.5	206.9	1,029.4

We consider that this reflects a prudent and efficient level of forecast operating expenditure that will enable us to meet the operating expenditure objectives of the Rules[8] and will enable us to continue to drive further efficiencies in the business.

7 Economic Benchmarking Results for the Australian Energy Regulator's 2020 TNSP Annual Benchmarking Report, Economic Insights, October 2020, page 62.

8 National Electricity Rules, clause 6A.6.6(a).

6.4.3 Changes from the draft Revenue Proposal

Our draft Revenue Proposal included total forecast operating expenditure of $1,038.9m, which reflected a $0 change from actual/forecast operating expenditure in the 2018-22 regulatory period at that time, consistent with our no real growth target.

Since we published our draft Revenue Proposal in September 2020, we have made several minor changes. These include:

- adjustments to remove movements in provisions and NCIPAP costs from our 2018/19 base year, following advice from AER staff to remove these items. We explain the reasons for this in Section 6.4.1;
- an adjustment to remove forecast network support costs in the 2018-22 regulatory period from our calculation of a no real growth target. This is also explained in Section 6.4.1;
- an adjustment to update forecast figures to reflect the latest inflation data, as published by the Reserve Bank of Australia (RBA) in November 2020;
- an adjustment of our output growth factor from 0.4% to 0.3% as a result of updated energy throughput forecasts; and
- adjustment of our productivity factor from 0.8% to 0.5% per annum, consistent with our no real growth target between the current and next regulatory periods.

Table 6.5 summarises the difference in total forecast operating expenditure between our draft Revenue Proposal and our Revenue Proposal.

Table 6.5: Forecast operating expenditure comparison ($m real, 2021/22)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Draft Revenue Proposal(1)	206.5	208.5	208.2	208.0	207.7	**1,038.9**
Revenue Proposal(2)	203.9	206.3	205.8	206.5	206.9	**1,029.4**
Difference ($m)	(2.6)	(2.2)	(2.5)	(1.5)	(0.8)	**(9.5)**
Difference (%)	(1.2)	(1.1)	(1.2)	(0.7)	(0.5)	**(0.9)**

(1) Excludes debt raising costs.

(2) Reflects underlying operating expenditure, excluding movements in provisions, debt raising, network support and NCIPAP costs.

6.5 Operating expenditure forecasting methodology

This section presents our operating expenditure forecasting methodology and provides detail about the base-step-trend approach applied to develop our operating expenditure forecast for the 2023-27 regulatory period. More detail is included in Appendix 6.01 Forecast Operating Expenditure Methodology and Model.

6.5.1 Operating expenditure forecasting methodology

We have based our forecasting approach on the AER's 2013 Expenditure Forecast Assessment Guideline for Electricity Transmission[9]. The AER's base-step-trend methodology was used for the majority of operating expenditure categories, with category-specific (or bottom-up) forecasts developed for the AEMC Levy, network support costs and debt raising costs. The methodology used to prepare our operating expenditure forecast is summarised in Figure 6.2 and explained in the following sections.

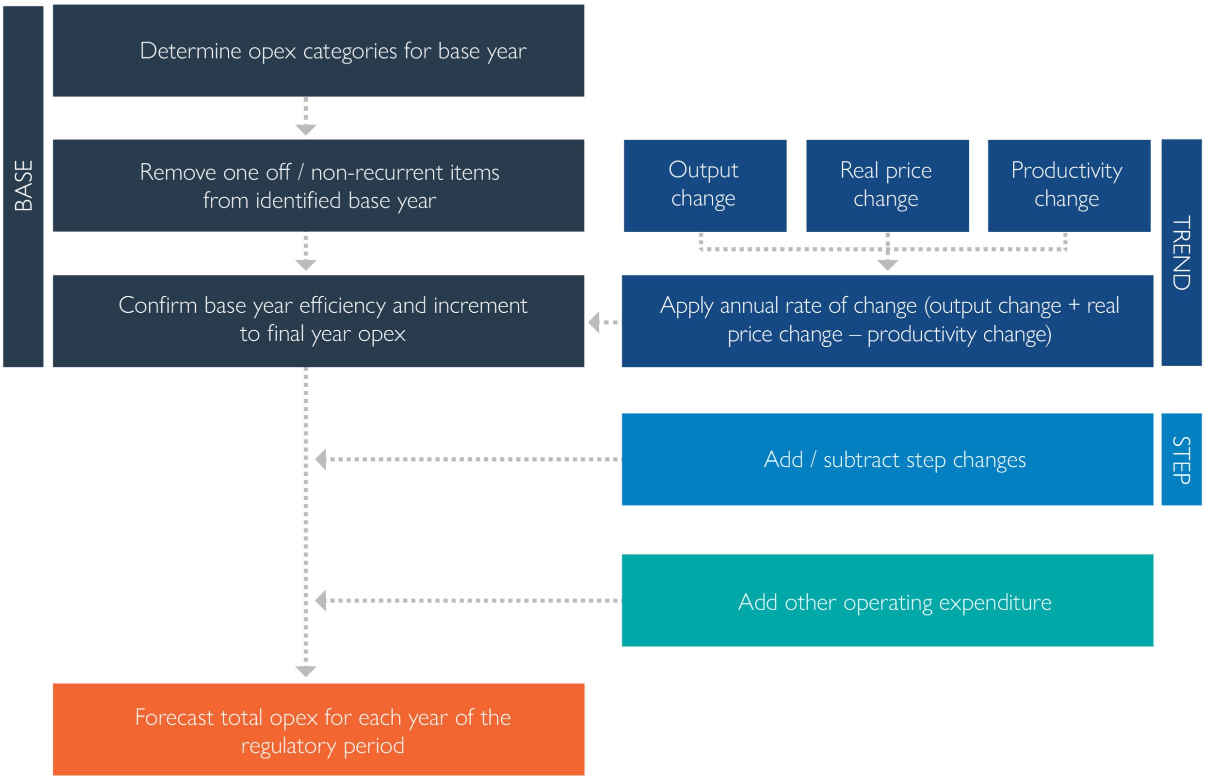
Our forecasting methodology is largely consistent with that used and accepted by the AER in its Final Decision for our 2018-22 regulatory period. It is also largely consistent with our Expenditure Forecasting Methodology submitted to the AER in June 2020, other than a change in approach to forecasting insurance. We have updated our Expenditure Forecasting Methodology to reflect these amendments (refer to Appendix 5.03).

We decided to forecast insurance costs (premiums and self-insurance) from within our base year operating expenditure, rather than through a bottom-up approach. This is due to the significant uncertainty in the insurance market which is in a hard phase of the cycle. Forecasts from our insurance brokers, Marsh, indicate that insurance premiums for our current insurance coverage may increase by $17.0m (41%) in the 2023-27 regulatory period compared to our total actual/forecast insurance premium costs for the 2018-22 regulatory period. Our consideration of insurance is discussed further in Section 6.7.1.

9 Expenditure Forecast Assessment Guideline for Electricity Transmission, Australian Energy Regulator, November 2013.

Our efficient base year operating expenditure costs includes only those costs for the provision of prescribed transmission services, consistent with our Cost Allocation Methodology (CAM) approved by the AER in 2008. This also applies to the rate of change parameters and other costs included in our forecast operating expenditure. The resulting total operating expenditure forecasts therefore relate only to the provision of prescribed transmission services, consistent with our CAM.

Figure 6.2: Powerlink's operating expenditure forecasting methodology



6.6 Application of the base-step-trend methodology

This section outlines how we have applied the AER's base-step-trend methodology to forecast our operating expenditure and the inputs and assumptions used for each element of the base-step-trend. We have also included a brief guide to our key inputs and assumptions for operating expenditure in Attachment 1.

6.6.1 Efficient base year

Base year selection

We have selected 2018/19 as the base year for our base-step-trend model as it is reflective of a typical year of operations, i.e. without the potential uncertainties and inconsistencies in expenditure associated with COVID-19 in 2019/20 and 2020/21. It also reflects a revealed cost approach as is the AER's preference.

We considered the use of 2019/20 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. It also reflects our standard approach of using Year 3 as the base year for developing our opex forecasts. However, the impact of COVID-19 means this is not a typical year of operation for the following reasons:

- we modified work methodologies for field and office-based staff to respond to physical distancing requirements. This included travel limits for field staff to only faults, emergencies and critical maintenance, and the need to provide additional vehicles to ensure physical distancing requirements were met while travelling to and from work sites;
- works were replanned/rescheduled where COVID-19 distancing requirements could not be met. This included deferral of some routine maintenance activities, and an increase in condition-based and corrective maintenance to prioritise staff safety while maintaining network reliability standards; and
- additional costs were incurred to manage Powerlink's COVID-19 response, for example cleaning, sanitisation and signage.

These adjustments demonstrate variations from typical operation and have resulted in transfers of expenditure between cost categories.

We also considered the use of 2020/21 as the base year to forecast operating expenditure. However, we concluded that there is potential for actual 2020/21 costs to also include atypical expenditure due to COVID-19 impacts.

As a result we determined that 2018/19 is the most appropriate choice for our base year opex, given potential issues around the alternative years considered.

We engaged HoustonKemp to perform an independent review of the efficiency of our 2018/19 operating expenditure and our performance against other TNSPs. This is discussed further in this section and HoustonKemp's report is provided in Appendix 4.01.

Base year adjustments

We reviewed actual expenditure in the base year to identify any non-recurrent items or items that are not considered to reflect an efficient level of recurrent operating expenditure. This review led to the following adjustments:

- minus $0.3m (2018/19 nominal) to remove expenditure associated with a NCIPAP project which occurred under the STPIS[10]; and
- minus $1.0m (2018/19 nominal) to remove movements in provisions from our base year expenditure[11].

We outline these adjustments and the resultant base year expenditure in Table 6.6.

Table 6.6: Adjusted operating expenditure items in 2018/19 base year ($m nominal)

Base year expenditure adjustment	Total
2018/19 unadjusted base year operating expenditure	**193.3**
Adjustment to remove NCIPAP project costs	(0.3)
Adjustment for movements in provisions	(1.0)
2018/19 base year operating expenditure – efficient base year	**192.0**

Operating expenditure associated with the AEMC Levy, 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 6.7).

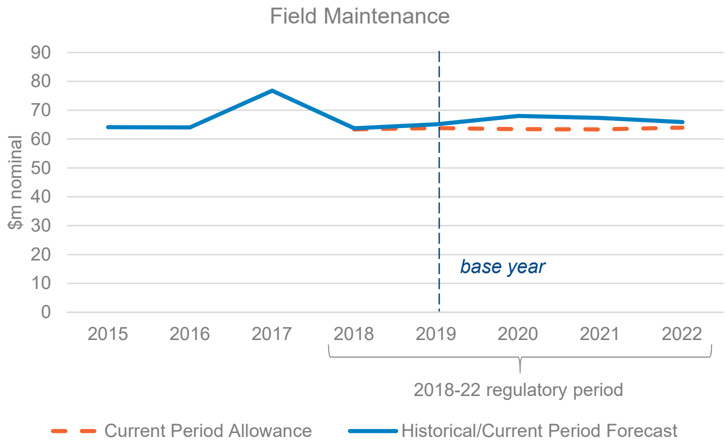
Category analysis of controllable operating expenditure

To confirm the reasonableness of our selected base year, we assessed the relative performance of each major category of controllable operating expenditure against the trend from 2014/15 (the base year for our 2018-22 Revenue Proposal). Our performance in the 2018-22 regulatory period is presented in Chapter 4 Historical Capital and Operating Expenditure. Figure 6.3 demonstrates that at a category level, the proposed 2018/19 base year closely aligns to trend.

[10] Consistent with clause 5.2(r)(1) of Version 5 of the STPIS.

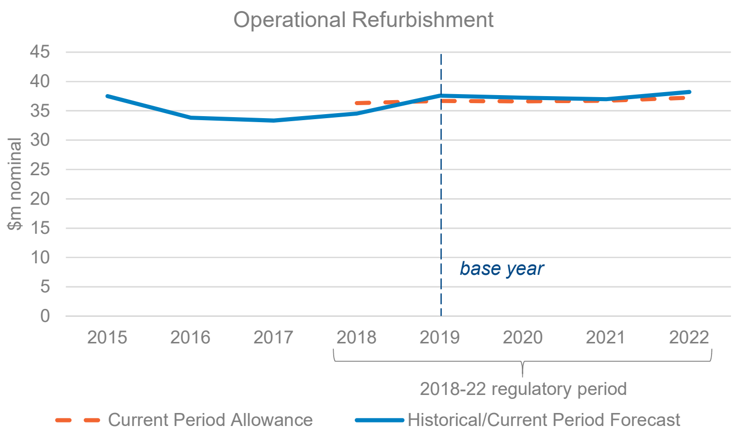
[11] Consistent with the Expenditure Forecast Assessment Guideline for Electricity Transmission, Australian Energy Regulator, November 2013, page 22.

Figure 6.3: Category analysis of controllable operating expenditure ($m nominal)



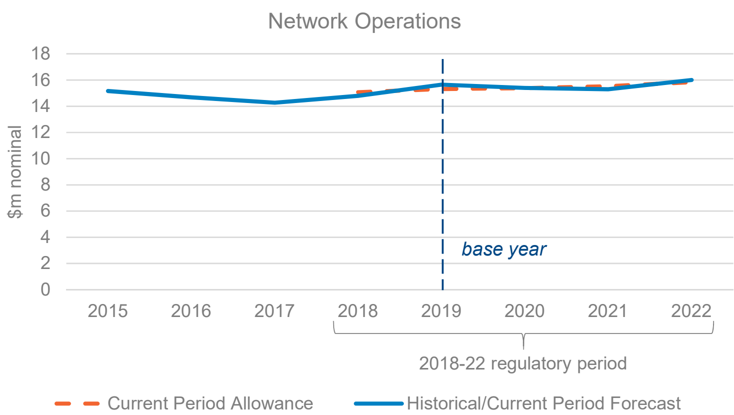
Field maintenance includes routine, condition-based, and corrective maintenance.

A one-off increase in total field maintenance in 2016/17 was driven by condition-based maintenance works to decommission a transmission line. 2019/20 was impacted by maintenance required to address several transmission line and substation failures, as well as COVID-19 travel and work practice restrictions. We adjusted our work practices to a focus on localised condition-based and corrective maintenance.



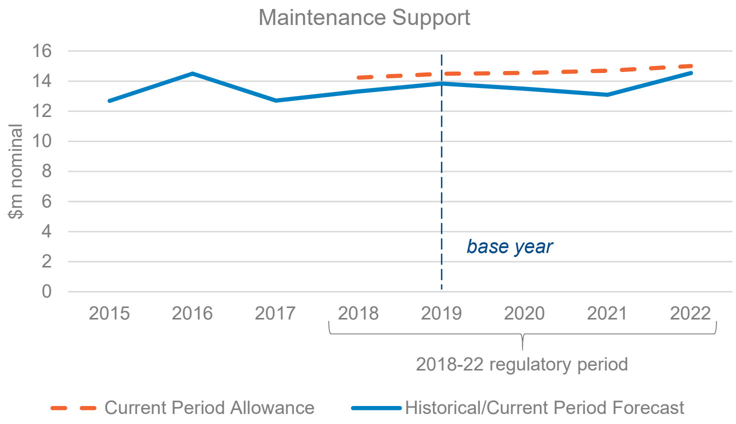
Operational refurbishment involves activities that return an asset to its pre-existing condition or function.

There is limited difference in actual spend compared to the AER's allowance for this category over the 2018-22 regulatory period. The primary driver of this category is insulator replacement works. We undertook works to address an early life failure risk for polymer insulators to address potential safety, reliability and security issues. This contributed to a minor increase in operational refurbishment expenditure above the AER's allowance.



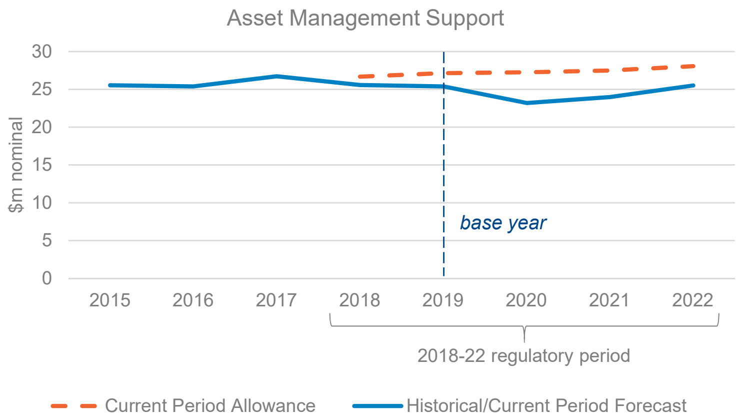
Network operations include control centre functions as well as additional operational support activities.

There is limited difference in our actual spend compared to the AER's allowance for this category over the 2018-22 regulatory period, and gradual growth in this category over the regulatory period. This is due to increased complexity in managing the network, as a result of system strength and the rapid growth in IBR.



Maintenance support includes activities required to develop and maintain the systems to support field maintenance.

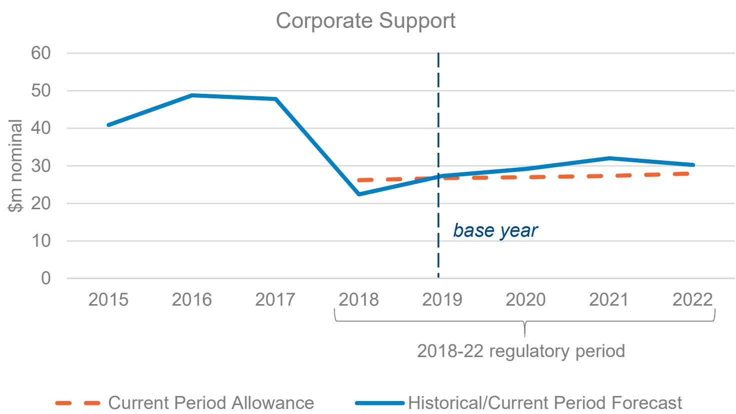
Expenditure in this category is slightly below the AER's allowance, driven in part by our renegotiation of contracts for electricity, land, and rental costs across some field sites. Reductions to field support contract rates have contributed to lower forecasts for this category.



Asset management support includes activities required to support the strategic development and continued asset management of the network.

Expenditure in this category has been below the AER's allowance throughout the period. Workplace reform and a restructure at the end of the 2013-17 regulatory period drove efficiencies and improved practices in this category, with a focus on increased utilisation of internal resources. In 2019/20, we reduced external works due to COVID-19.

We shifted our focus from Asset Management Support activities to support preparatory works for capital projects.



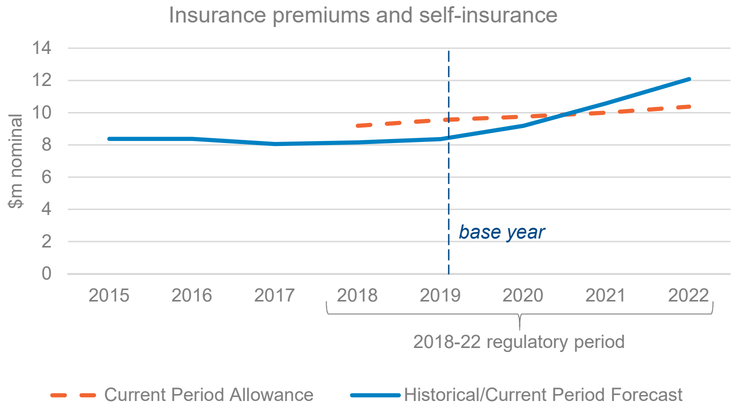
Corporate support includes the activities required to ensure adequate and effective corporate governance.

We achieved a material reduction in corporate support costs during 2017/18 after a corporate restructure and high levels of one-off expenditure in 2015/16 and 2016/17. Our reduced spend has been maintained over the 2018-22 regulatory period. Increases in 2020-22 reflect costs associated with the revenue determination process, which were not incurred in the first two years.

Category analysis of non-controllable operating expenditure

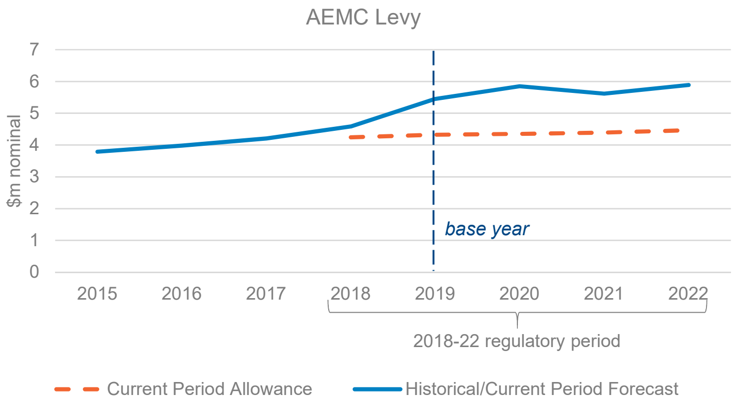
Increases in key non-controllable operating expenditure categories have impacted our ability to live within the AER's allowance for the 2018-22 regulatory period. Figure 6.4 outlines key trends in insurance premiums and self-insurance, and the AEMC Levy over the period 2014/15 to 2021/22.

Figure 6.4: Category analysis of non-controllable operating expenditure ($m nominal)



Insurance costs (including both insurance premiums and self-insurance) have increased since 2018/19 and are forecast to continue to rise over the remainder of this regulatory period into the next.

These increases are due to a material rise (approximately 18% per annum in nominal terms) in insurance premiums as the insurance market enters a hard phase.



Over the 2018-22 regulatory period, the AEMC Levy has increased in nominal terms by $5.6m (25.8%) to date above the AER's allowance. A slight decline is forecast for 2020/21 based on the latest information from the Queensland Government.

This cost is not within Powerlink's control. The drivers for this cost are explained further in Section 6.7.2, as well as Chapter 4 Historical Capital and Operating Expenditure.

Efficiency of base year

This section provides detail about our benchmarking outcomes relative to our proposed 2018/19 base year. Further information about our historical benchmarking performance is included in Chapter 4 Historical Capital and Operating Expenditure.

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 (five) of TNSPs in Australia. The AER acknowledges this limitation in applying its benchmarks to TNSPs[12].

We understand that to address this in part, the AER has moved towards a line-of-best-fit approach for productivity benchmarking rather than an average annual growth rate method (which measures the productivity growth rate between the first and last observations). We agree that the line-of-best-fit approach is a more appropriate method to examine the productivity of TNSPs over time.

Our Revenue Proposal Reference Group (RPRG) also recognised that changes to certain inputs in the analysis can improve the benchmarking performance of a business without improvements to outcomes for customers[13]. Our customers want us to focus on genuine improvements in capital and operating expenditure, rather than changes that might improve benchmarking performance but deliver no tangible customer benefits. We have had regard to this feedback as we developed our operating expenditure forecasts and our no real growth approach is designed to deliver real benefit to customers.

In our discussions with customers and the AER, we reinforced that our primary focus is to ensure that we undertake works that deliver safe, secure and reliable transmission services in a prudent and efficient manner. While we are very mindful of the AER's benchmarking and the high-level insights it might suggest, we do not and will not undertake works simply to convey the appearance of improvement under the AER's benchmarks.

We engaged HoustonKemp to undertake an independent review of our base year operating expenditure and benchmark it against other TNSPs to examine productivity trends. HoustonKemp's report is provided in Appendix 4.01.

12 Annual Benchmarking Report – Electricity transmission network service providers, Australian Energy Regulator, November 2020, page 16.
13 Minutes of the Revenue Proposal Reference Group, Powerlink, December 2019, https://www.powerlink.com.au/2023-27-regulatory-period.

To support our goal to have a Revenue Proposal that is capable of acceptance by our customers, the AER and Powerlink, we provided an early copy of HoustonKemp's report to the AER for consideration. We also provided a copy to our Customer Panel after publication of the AER's 2020 Economic Benchmarking Report in November 2020.

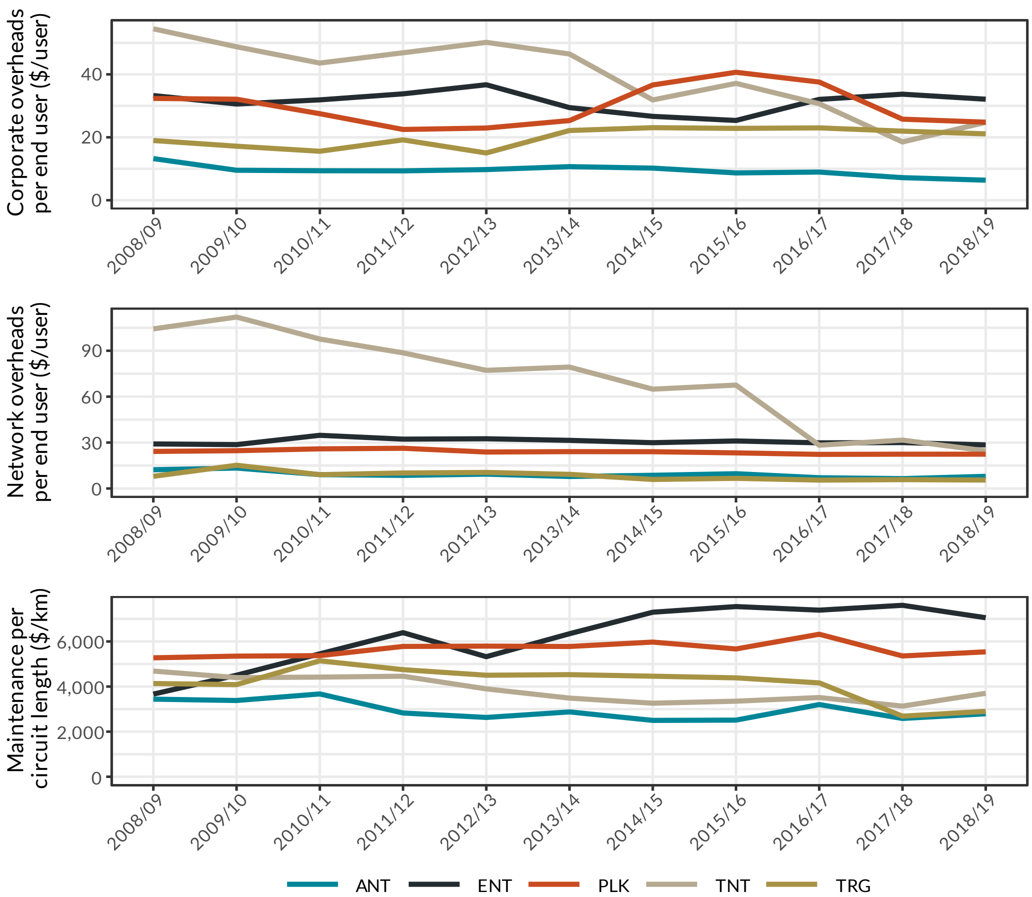
HoustonKemp's key findings on our base year operating expenditure were as follows:

> *The AER's most recent benchmarking results for Powerlink, both in absolute and trend terms, shows that Powerlink has been responding to the incentives in the regulatory framework and is operating relatively efficiently when compared to its peers.*
>
> *In other words, consistent with the AER's application of the benchmarking framework for TNSPs and its recognition of the limitations of that framework, the benchmarking analysis does not provide any basis to conclude that Powerlink's revealed 2018/19 operating expenditure is 'materially inefficient', and to overturn the presumption that the incentive mechanisms in the regulatory framework (in particular the EBSS) should lead to revealed operating expenditure being an accurate reflection of efficient expenditure.*
>
> *Further, Powerlink's relative benchmarking performance in 2018/19 is consistent with its relative performance in 2014/15, where the AER accepted actual operating expenditure as representing an efficient base year for the current regulatory period*[14].

We have made a substantial effort in the current 2018-22 regulatory period to improve our operating performance. HoustonKemp found that we had delivered a significant reduction in operating expenditure in 2017/18 and a correlated improvement in benchmark performance.

As well as analysing the AER's benchmarking results, HoustonKemp also carried out a detailed category analysis of operating expenditure over time and against our TNSP peers. Figure 6.5 presents a category analysis of TNSP operating expenditure for key categories over the period 2008/09 to 2018/19.

Figure 6.5: TNSP operating expenditure (category analysis) by key category, adjusted[(1)]



Source: Efficiency of Powerlink's base year operating expenditure, HoustonKemp, November 2020

(1) Values have been adjusted and inflation has been applied by HoustonKemp (refer to Appendix 4.01 Efficiency of Powerlink's Base Year Operating Expenditure Report).

14 Efficiency of Powerlink's base year operating expenditure, HoustonKemp, November 2020, pages 5-6.

HoustonKemp's detailed category analysis showed:

- Our corporate overheads (on a per end user basis) were lower in 2018/19 in real terms than in 2008/09. The increase above trend in corporate support costs in 2015/16 and 2016/17 arose from costs associated with business restructuring, whilst the significant reduction in 2017/18 arose from the write back of provisions not required for the restructure.
- Our network overheads per end user were lower in 2018/19 in real terms than in 2008/09, and approximately equal with TasNetworks and ElectraNet, which is consistent as these three TNSPs have the lowest connection density.
- Our maintenance costs per circuit length were approximately five per cent higher in 2018/19 in real terms than in 2008/09, consistent with the increasing age of our network over time.

From this analysis, HoustonKemp concluded the following:

> *Our detailed category analysis of Powerlink's operating expenditure over time and against its peers further supports [the conclusion that its operating expenditure is not materially inefficient], and indicates that Powerlink's operating expenditure performance across its major operating expenditure categories has been improving over time, and that its relative performance is consistent with the key characteristics of its network relative to other stand-alone TNSPs*[15,16].

Based on HoustonKemp's independent advice on the efficiency of our 2018/19 base year, we consider that our performance is comparable to our TNSP peers. We recognise there is a need to continue to pursue improvements to operating expenditure productivity to drive more prudent and efficient operations and to achieve meaningful customer outcomes. Our overall operating expenditure target of no real growth is consistent with this aim.

Analysis of Powerlink's total operating expenditure

In addition to HoustonKemp's analysis, we have also considered our overall operating expenditure relative to three key parameters – circuit length, customer numbers and energy transported, over the period 2005/06 to 2018/19. We have also forecast our performance for 2019/20 to 2026/27 and provided this information in Figures 6.6 to 6.8. These metrics have been provided in response to feedback from our RPRG to provide further information about our anticipated forecast operating expenditure performance over the 2023-27 regulatory period[17].

Our historical and forecast performance against these metrics indicates:

- We have improved considerably over the 2018-22 regulatory period and our operating expenditure against all three metrics now reflects levels similar to, or better than, 2006.
- Our forecast operating expenditure for the 2023-27 regulatory period, driven by our no real growth target, is anticipated to result in the retention of improvements realised in the current regulatory period and demonstrates that we will maintain a prudent and efficient level of operating expenditure.

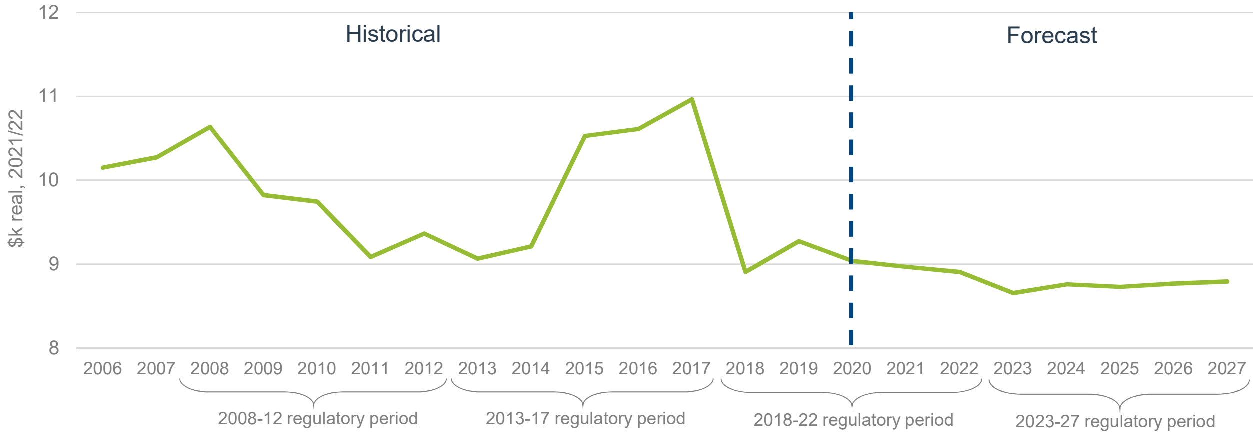
We provide further observations on each metric below. Note that, for each metric, a lower/declining amount represents improving performance.

15 As discussed in Chapter 4 Historical Capital and Operating Expenditure, HoustonKemp concluded that the performance of TasNetworks largely reflects the outcome of the merger of transmission and distribution business and is therefore not representative of the outcomes for a stand-alone TNSP.

16 Efficiency of Powerlink's base year operating expenditure, HoustonKemp, December 2020, pages 5-6.

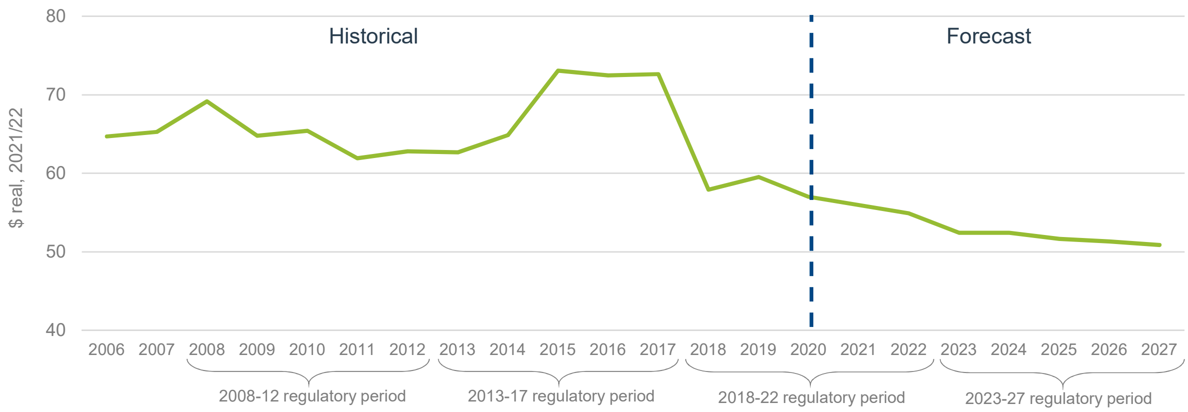
17 Minutes of the Revenue Proposal Reference Group, Powerlink, December 2020, https://www.powerlink.com.au/2023-27-regulatory-period.

Figure 6.6: Powerlink total operating expenditure per circuit km ($k real, 2021/22)



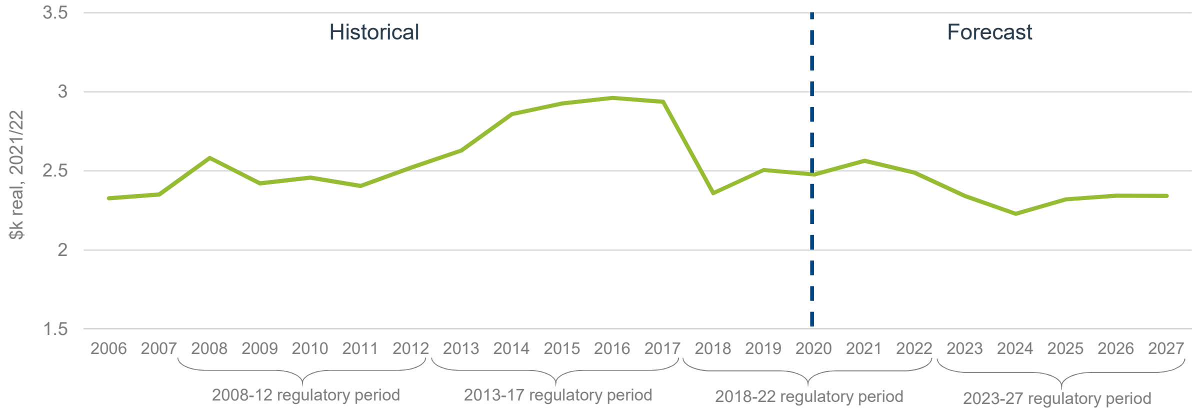
- In 2019/20, operating expenditure per km reduced by 11% compared to the level in 2005/06, and is down 18% compared to a peak observed in 2016/17.
- Over the period 2019/20 to 2026/27, this metric is expected to reduce at a rate of 0.42% per annum, to a level 13% below that seen in 2005/06.
- Over the period 2005/06 to 2026/27, the average annual rate of change is forecast to be minus 0.77%.
- No material change in our circuit kilometres is forecast in the 2023-27 regulatory period, which would also contribute to any change in this metric.

Figure 6.7: Powerlink total operating expenditure per customer ($ real, 2021/22)



- In 2019/20, operating expenditure per customer reduced by 12% compared to the level seen in 2005/06, and is down 22% compared to a peak observed in 2014/15.
- Over the period 2019/20 to 2026/27, this metric is expected to reduce at a rate of 1.67% per annum, to a level 21% below that seen in 2005/06.
- Over the period 2005/06 to 2026/27, the average annual rate of change is forecast to be minus 1.39%.
- The main driver of the decline in this metric over the period 2019/20 to 2026/27 is forecast population growth in Queensland. An increase in customer numbers and forecast no real growth in operating expenditure results in a gradual reduction in operating expenditure costs per customer.

Figure 6.8: Powerlink total operating expenditure per GWh ($k real, 2021/22)



- Forecasts of operating expenditure per GWh are largely influenced by forecast trends in energy transmission sourced from AEMO's 2020 Electricity Statement of Opportunities (ESOO) and the 2020 Integrated System Plan (ISP).
- In 2019/20, operating expenditure per GWh was 6% higher than the level seen in 2005/06, but 16% lower than the peak observed in 2016.
- Over the period 2019/20 to 2026/27, this metric is expected to reduce at a rate of 1.3% per annum, to a level 0.6% above that seen in 2005/06.
- Over the period 2005/06 to 2026/27, the average annual rate of change is forecast to be minus 0.27%.
- The driver of a slight increase in this rate seen in the year 2020/21 is reduced energy throughput in Queensland as a result of COVID-19 induced economic impacts. Over the period 2022 to 2024, an increase in energy flows throughout Powerlink's network and a subsequent decline in operating expenditure per GWh is forecast as a result of economic recovery from COVID-19, the commissioning of the QNI Minor interconnector upgrade, and the closure of Liddell Power Station. Beyond 2023/24, energy transfers in Queensland are forecast to reduce.

Overall, we consider that the forecast outcomes under these metrics lend support to the reasonableness and efficiency of our operating expenditure forecasts for the next regulatory period.

6.6.2 Rate of change

Total rate of change

The overall real rate of change in the base-step-trend model is a function of the forecast change in network output, changes in real input costs (labour and materials) and changes in productivity. The calculation method for the total rate of change is shown in Figure 6.9, and is consistent with the AER's 2013 Expenditure Forecast Assessment Guideline for Electricity Transmission and our Expenditure Forecasting Methodology in Appendix 5.03.

Figure 6.9: Forecast rate of change method

Table 6.7 shows the sum of forecast changes in output, real prices and productivity over the 2023-27 regulatory period. Our forecast average annual rate of change over the 2023-27 regulatory period is 0.3%.

Table 6.7: Forecast real annual rate of change (% per annum)

Rate of change components	2022/23	2023/24	2024/25	2025/26	2026/27	Average
Output change	0.3	1.4	(0.4)	0.1	0.2	**0.3**
Real price change	0.3	0.4	0.6	0.8	0.5	**0.5**
Productivity change	0.5	0.5	0.5	0.5	0.5	**0.5**
Total rate of change	**0.0**	**1.2**	**(0.3)**	**0.4**	**0.2**	**0.3**

Table 6.8 shows the annual increase or decrease in forecast operating expenditure due to the rate of change being applied in each year of the regulatory period.

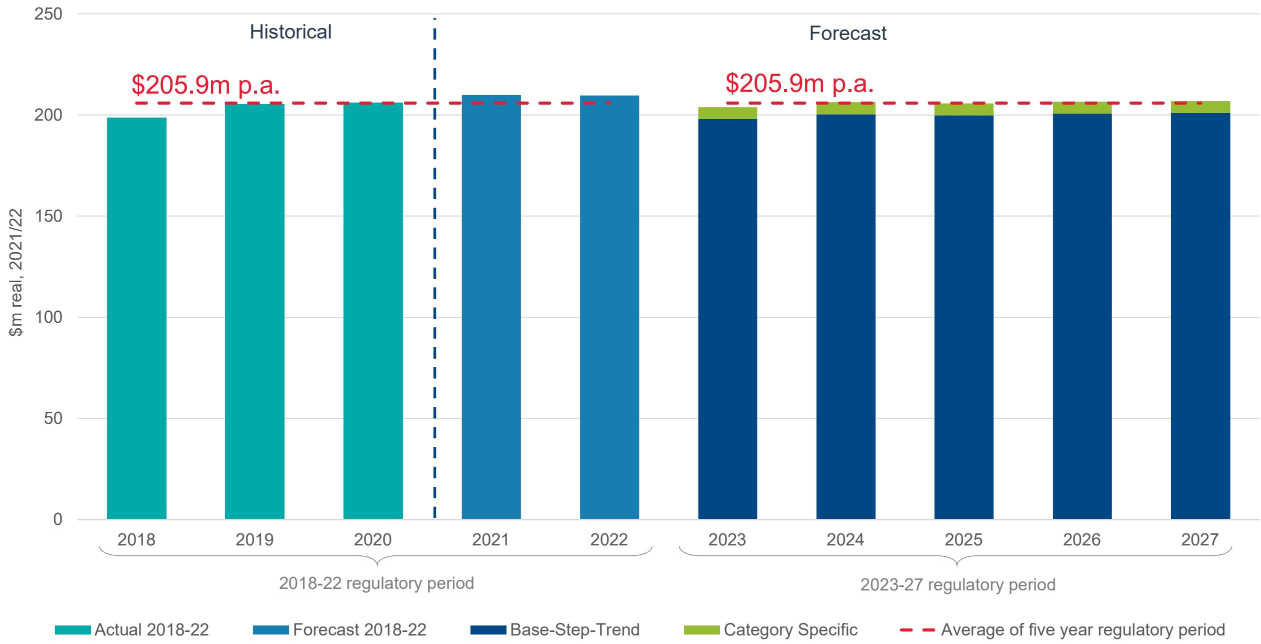
Table 6.8: Forecast real annual rate of change ($m real, 2021/22)

Rate of change components	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Output change	0.5	3.2	2.4	2.6	2.9	**11.6**
Real price change	0.5	1.2	2.4	4.0	5.0	**13.1**
Productivity change	(0.9)	(2.0)	(2.9)	(3.9)	(4.9)	**(14.7)**
Total rate of change	**(0.0)**	**2.5**	**1.9**	**2.6**	**3.0**	**10.0**

It is important to note that while the total rate of change within the base-step-trend operating expenditure forecast is greater than zero, when we take into account the AEMC Levy category-specific forecast, there is no real growth in total operating expenditure between the 2018-22 and 2023-27 regulatory periods.

The annual average operating expenditure is identical at $205.9m per annum between the 2018-22 and 2023-27 regulatory periods, as demonstrated by Figure 6.10.

Figure 6.10 Actual/forecast average annual operating expenditure ($m real, 2021/22)[(1)]



(1) Reflects underlying operating expenditure, which excludes movements in provisions, debt raising, network support and NCIPAP costs.

Output growth

Output growth is the expected change in network output, measured by the four parameters outlined in Table 6.9, weighted by their assessed share of gross revenue. Weighting factors are defined by the AER as part of its economic benchmarking of TNSPs.

Table 6.9: Output change factors

Output measure	Description	Weighting[1]
Energy throughput	Forecast growth of delivered energy within Queensland, plus energy delivered through interconnectors to / from NSW measured in GWh. This information is sourced from the Central Scenario of AEMO's 2020 ESOO and AEMO's 2020 ISP. Energy throughput within Queensland is forecasted to reduce slightly. There is forecast growth in energy throughput early in the 2023-27 regulatory period on the QNI. This is a result of the commissioning of the 2018 ISP recommended Group 1 QNI minor upgrade. The project entails uprating the QNI by 2022 prior to the closure of Liddell Power Station in NSW.	14.9%
Ratcheted Maximum Demand	Ratcheted Maximum Demand is the ratcheted non-coincident maximum demand. Non-coincident maximum demand is the maximum demand of each individual connection point in a year measured in MVA. This information is sourced from the Central Scenario of AEMO's 2020 ESOO and Powerlink's 2020 Transmission Annual Planning Report (TAPR). The maximum demand within Queensland is forecast to remain relatively stable for the 2023-27 regulatory period. We forecast an increase in maximum demand following the commissioning of the 2018 ISP recommended Group 1 QNI minor upgrade as identified in the energy throughput section above.	24.7%
Number of customers	This is based on an aggregate number of customers for the Distribution Network Service Providers (DNSPs), Ergon Energy and Energex, identified in the AER's 2020-25 Final Decision models and Powerlink's directly-connected customers. For 2026/27, Ergon Energy and Energex's customer numbers were trended based on a simple linear regression. Based on this approach, customer numbers are forecasted to increase by 143,000 over the 2023-27 regulatory period.	7.6%
Circuit length	Circuit length is the total transmission line circuit length measured in kilometres sourced from Powerlink's Enterprise Resource Planning database (SAP) Plant Maintenance Module. Powerlink has forecast no overall increase in circuit length over the 2023-27 regulatory period and has adjusted the forecast of circuit kilometre length down from 14,528km to 14,472km to reflect forecast transmission line decommissioning over the 2023-27 regulatory period. This adjustment reflects our focus on reducing both forecast capital and operating expenditure on assets at the end of technical and economic life, for which there may be no enduring need.	52.8%

(1) Annual Benchmarking Report – Electricity Transmission Network Service Providers, Australian Energy Regulator, November 2020.

Table 6.10 presents the forecast annual output growth factors for the 2023-27 regulatory period, along with total output growth after the AER's updated weightings from its 2020 Economic Benchmarking Report are applied. The last two years of the current regulatory period are shown for completeness.

Table 6.10: Output growth factors (% per annum)

Output components	2020/21[1]	2021/22[1]	2022/23	2023/24	2024/25	2025/26	2026/27	Average[2]
Energy throughput	(4.2)	2.3	2.8	6.1	(4.3)	(0.6)	0.4	**0.9**
Ratcheted Maximum Demand	-	-	-	1.5	0.4	0.3	0.2	**0.5**
Number of Customers	1.2	1.2	1.2	1.2	1.2	1.2	1.2	**1.2**
Circuit length	-	-	(0.5)	-	0.1	-	-	**(0.1)**
Total output growth	**(0.5)**	**0.4**	**0.3**	**1.4**	**(0.4)**	**0.1**	**0.2**	**0.3**

(1) Figures for 2020/21 and 2021/22 are calculated using the updated 2020 weighting factors, and therefore do not represent rates of change presented in the 2018-22 Revenue Proposal.

(2) Average of the 2023-27 regulatory period.

Real price growth

Real price growth is the forecast real change in input costs, measured for labour and materials. We consider our forecast of labour and materials price changes represent a realistic forecast of input increases over the 2023-27 regulatory period.

Our forecast of labour input price changes is based on a simple average of two Wage Price Index (WPI) forecasts:

- an independent forecast of Electricity, Gas, Water and Waste Services (EGWWS) WPI for Queensland developed by BIS Oxford Economics (BISOE); and
- the Deloitte Access Economics (DAE) National Utilities WPI forecast prepared for the AER for the Draft Decisions of the Victorian DNSPs in September 2020[18].

Both forecasts have been adjusted to account for the impact of the Federal Government's Superannuation Guarantee increase, to be implemented over the period 1 July 2021 to 1 July 2025 in line with recent AER Draft Decisions for Victorian DNSPs in September 2020[19]. Our approach to forecasting WPI is set out in Chapter 7 Escalation Rates and Project Cost Estimation.

Table 6.11 presents these forecasts along with the simple average forecast that has been used in the rate of change calculations. The average annual labour price change over the 2023-27 regulatory period is 0.7%. The last two years of the current regulatory period are shown for completeness.

Table 6.11: Forecast real labour price growth, including superannuation guarantee (% per annum)

WPI forecasts	2020/21(1)	2021/22(1)	2022/23	2023/24	2024/25	2025/26	2026/27	Average(2)
BISOE EGWWS	0.6	1.3	1.1	1.0	1.3	1.3	0.9	**1.1**
DAE National Utilities	0.4	-	(0.3)	-	0.4	1.0	0.5	**0.3**
Average	**0.5**	**0.6**	**0.4**	**0.5**	**0.9**	**1.1**	**0.7**	**0.7**

(1) Figures for 2020/21 and 2021/22 are calculated using the updated 2020 weighting factors, and therefore do not represent rates of change presented in the 2018-22 Revenue Proposal.

(2) Average of the 2023-27 regulatory period. Figures for 2020/21 and 2021/22 are included for comparison only.

We propose a real materials price growth of zero in our expenditure forecasts for the 2023-27 regulatory period. This reflects the expectation that materials costs will increase in line with CPI and is consistent with other recent regulatory determinations[20]. Under current economic conditions, which include historically low levels of inflation and the impacts of COVID-19, it may be appropriate to apply materials cost escalators above CPI. We have chosen not to do this due to the uncertainty that exists in any alternative (non-CPI) materials forecast.

To develop our real price growth escalation forecasts for the 2023-27 regulatory period, we have applied weightings of labour to materials at a ratio of 70.4% to 29.6%. These weightings reflect those that have been applied by the AER and their consultant (Economic Insights) in the Annual TNSP Benchmarking Reports since 2017[21]. The AER sought and received data from TNSPs on the composition of their operating expenditure before arriving at the current weighting.

We have investigated the appropriateness of this weighting and found it is consistent with the split of labour and materials costs in our historical operating expenditure. Application of these weightings to the real labour and materials price growth results in an average real price change of 0.5% over the 2023-27 regulatory period.

Productivity growth

Productivity change measures the forecast productivity improvements for a business.

The AER currently applies an industry average to calculate productivity, based on operating expenditure Partial Factor Productivity (PFP) across all TNSPs. The current industry average is 0.3% per annum[22]. We discuss the benchmark techniques used by the AER to calculate productivity, and our historical performance, in Chapter 4 Historical Capital and Operating Expenditure.

18 See Draft Decisions for AusNet Services, Jemena, United Energy, CitiPower and Powercor, Australian Energy Regulator, September 2020.
19 Impact of changes to the superannuation guarantee on forecast labour price growth, Deloitte Access Economics, July 2020.
20 Final Decisions for Energex, Ergon Energy and SA Power Networks, June 2020.
21 Economic Benchmarking Results for the Australian Energy Regulator's 2020 TNSP Annual Benchmarking Report, Economic Insights, October 2020, page 62.
22 *Ibid.*

As part of its independent report on the efficiency of our 2018/19 base year, HoustonKemp also considered what productivity factor should be applied to Powerlink. HoustonKemp analysed the industry operating expenditure trend over the period 2005/06 to 2018/19[23] and concluded:

> *The benchmarking data suggest that the productivity factor applied for Powerlink for the forthcoming regulatory period, as a stand-alone TNSP, should be zero. Notwithstanding the application of a productivity growth rate of zero, Powerlink remains incentivised to continue to make efficiency gains in relation to its operating expenditure during the 2023-27 regulatory period, as a consequence of the EBSS[24].*

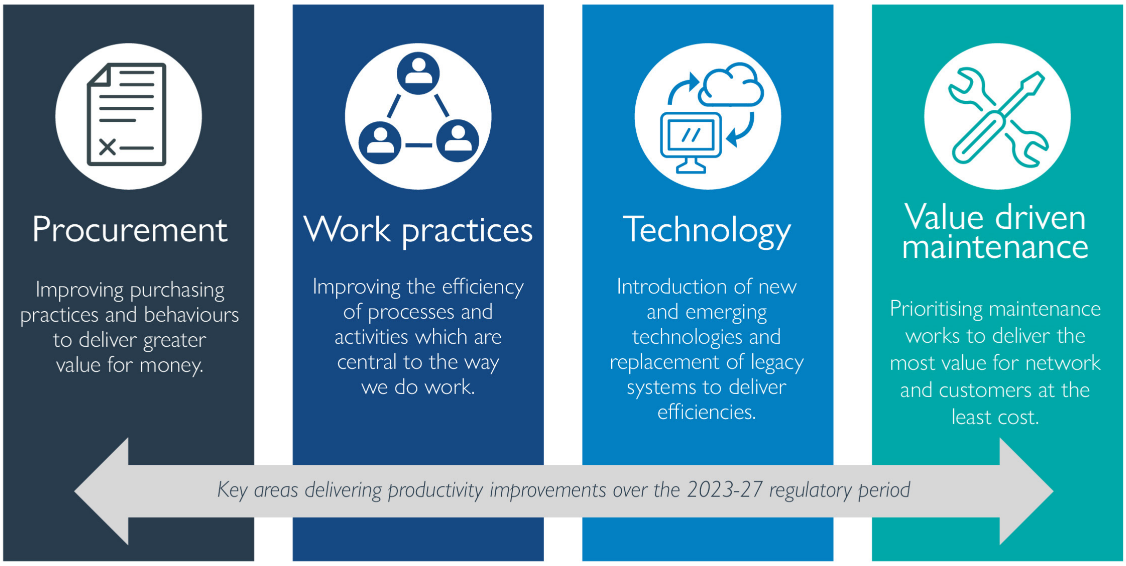
We considered HoustonKemp's independent analysis and findings and the AER's current industry average productivity factor of 0.3% in the development of our Revenue Proposal. Consistent with our target of no real growth in operating expenditure, we propose an annual productivity factor of 0.5%, which is higher than the industry average.

Feedback from our RPRG and the AER's CCP23 supported the high productivity target put forward in our draft Revenue Proposal. However, both groups sought further information on how we intend to meet this target.

Potential initiatives

To help achieve our overall target of no real growth in operating expenditure into the next regulatory period and thereby deliver on our proposed 0.5% productivity improvement each year, we have identified a number of potential productivity improvement categories (refer Figure 6.11). These initiatives are in various stages of development at this time.

Figure 6.11: Productivity categories for the 2023-27 regulatory period



Areas of focus and key initiatives under each of these themes could include:

- rationalisation of our direct purchasing and supply chain practices to reduce the frequency of procurement outside standing agreements with suppliers, to drive down costs;
- to explore options to reduce costs in vegetation management contract arrangements;
- application of emergent technologies to optimise field delivery and staff activities through improved work planning;
- delivery of our proposed office refit project (refer Chapter 5 Forecast Capital Expenditure), which should produce direct savings in utilities costs through reductions in the size of the occupied space and allow us to make more efficient use of available office space;
- core business Information Technology (IT) improvements and software upgrades which transition our core IT services to a more efficient operating platform. This will allow for programs to be modernised which is critical to support innovative technology applications and will help Powerlink avoid increased licence and operating costs associated with the continued use of the old operating environment;

[23] Efficiency of Powerlink's base year operating expenditure, HoustonKemp, December 2020, page 30.
[24] Efficiency of Powerlink's base year operating expenditure, HoustonKemp, December 2020, page 6.

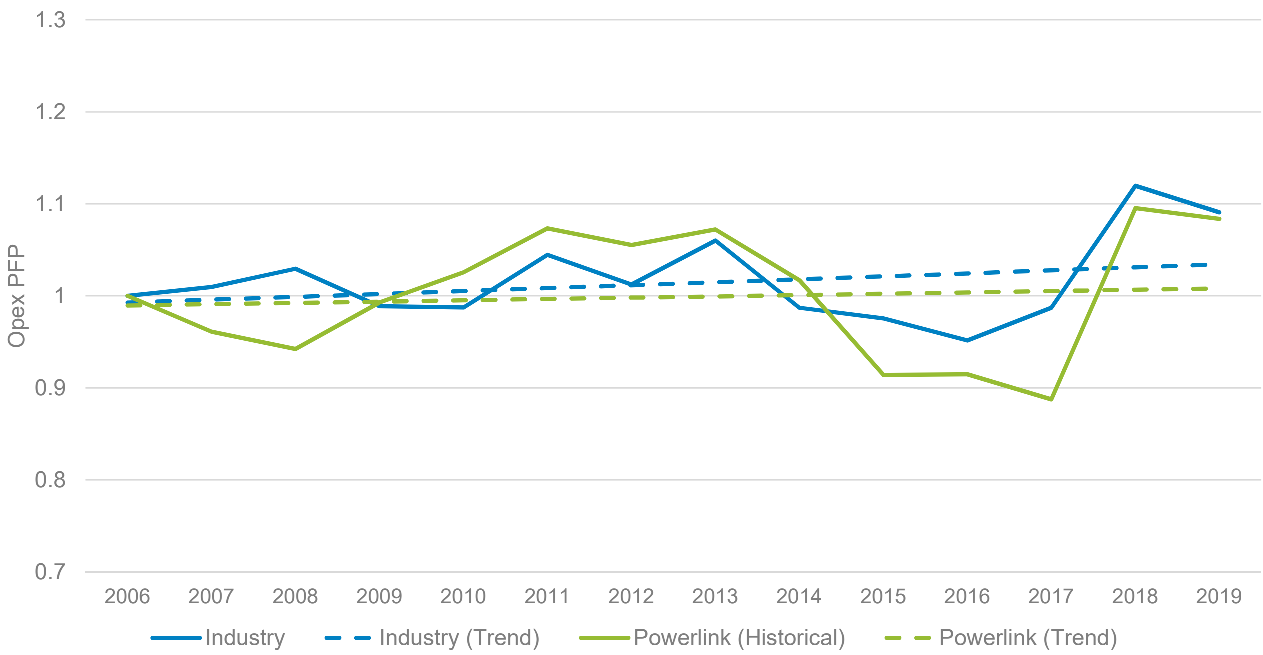
- establishment of an In-Vehicle Asset Management System (IVAMS) program across fleet vehicles to improve safety and driver education, as well as to enhance fleet management and reduce operating costs through savings on fuel, maintenance and vehicle insurance; and
- delivery of value driven maintenance practices. This involves further optimisation of maintenance works to deliver value for networks and customers at least cost. To realise the benefits from these programs, asset management policies and procedures have been prepared and candidate programs identified as of 2020/21, including potential applications across transmission line maintenance, civil inspections and transformer oil testing.

In response to customer feedback, we have also provided more detail in Appendix 6.02 Operating Expenditure Productivity Approach and Potential Initiatives. Further investigation into and the development of these and other initiatives will be undertaken in the normal course of business.

Productivity trend assessment

We have compared our historical operating expenditure productivity performance to the industry performance from 2005/06 to 2018/19, which is the most recent year that industry data is available. This is shown in Figure 6.12 together with the resulting productivity trend.

Figure 6.12: Powerlink and TNSP industry historical operating expenditure productivity



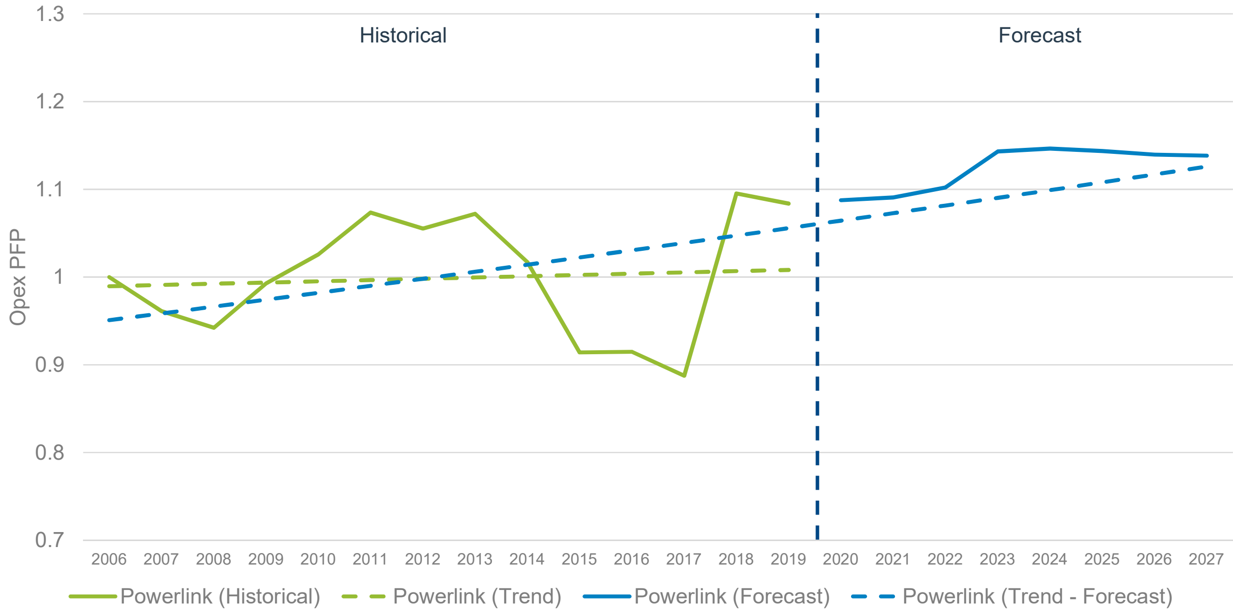
Source: Operating expenditure Partial Factor Productivity (PFP) measure published in the Annual Benchmarking Report – Electricity Transmission Network Service Providers, Australian Energy Regulator, November 2020.

Our operating expenditure productivity trend was 0.1% between 2005/06 and 2018/19, compared to an industry average of 0.3%. We improved our productivity substantially in 2017/18. This was driven by our 7% reduction in operating expenditure in the 2018-22 regulatory period compared to the 2013-17 regulatory period.

In response to feedback from our Customer Panel, we have also forecast our operating expenditure productivity over the period 2019/20 to 2026/27 to provide customers and the AER with a view of our productivity going forward. We have compared this to our historical performance (as shown in Figure 6.12) and restated the productivity trend for the whole period from 2005/06 to 2026/27 based on our forecast operating expenditure. This is shown in Figure 6.13.

To accurately forecast the productivity trend for other TNSPs would require forecast operating expenditure and output growth information from all other TNSPs. We are not in a position to seek such information and make this forecast.

Figure 6.13: Powerlink historical and forecast operating expenditure productivity



Source: Historical data is based on the operating expenditure Partial Factor Productivity (PFP) measure published in the Annual Benchmarking Report – Electricity Transmission Network Service Providers, Australian Energy Regulator, November 2020. Forecast data is based on Powerlink's own modelling.

We anticipate that our proposed 0.5% productivity factor for the 2023-27 regulatory period will drive a further uplift in our productivity in 2022/23, followed by a gradual improvement in our productivity trend over the remainder of the next regulatory period.

Our forecast operating expenditure in the next regulatory period results in a significant improvement in our operating expenditure productivity trend to 0.8% for the period 2005/06 to 2026/27. This would be an improvement on our historical productivity trend and is higher than the current industry productivity trend of 0.3%.

6.6.3 Step changes

We have decided not to pursue any operating expenditure step changes for the 2023-27 regulatory period. This followed detailed investigation of potentially material changes in our regulatory obligations.

As part of the preparation of our Revenue Proposal, we initially identified 27 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.

We had early discussions about several of these potential step changes with our RPRG in February 2020[25] and narrowed our step changes down to two in our Preliminary Positions and Forecasts Paper in August 2020[26] - cyber security and additional transmission ring-fencing cost impacts following the AER's review of its Transmission Ring-Fencing Guideline. We have reached a position not to pursue these further in our Revenue Proposal.

Our proposal to target no real growth in operating expenditure and not to pursue any operating expenditure step changes, was carefully considered. This included having regard to customer feedback about affordability, the reasonableness of uncertain step changes being funded through regulatory allowances up-front and our overarching requirement to continue to operate the network in a prudent and efficient manner, while meeting all our regulatory obligations.

On balance, we decided to take up the challenge of no step changes and no real growth in operating expenditure in the interests of customers and to drive the business harder to find further efficiencies and productivity improvements to become a world-class transmission service provider.

Feedback from the AER's CCP23 (refer to Appendix 3.02 Submissions on our draft Revenue Proposal) supported our proposal of no operating expenditure step changes, particularly given the cost pressures currently facing residential and commercial customers and in the face of economic uncertainty as a result of COVID-19.

25 Presentation to the Revenue Proposal Reference Group, Powerlink, February 2020, https://www.powerlink.com.au/2023-27-regulatory-period.

26 Preliminary Positions and Forecasts Paper, Powerlink, July 2020, https://www.powerlink.com.au/2023-27-regulatory-period.

Table 6.12 outlines those potential step changes that may result in an increase in costs in the 2023-27 regulatory period, which we have chosen not to seek a regulatory expenditure allowance for in our Revenue Proposal. Instead, in response to customer feedback to seek further improvements in our operating expenditure, we will work to manage these costs within our total forecast operating expenditure. Cyber security and potential additional transmission ring-fencing costs are discussed further below.

Further detail on step changes investigated in the preparation of our Revenue Proposal is also provided in Appendix 6.03 Operating Expenditure Step Changes Approach.

Table 6.12: Potential costs uplifts over the 2023-27 period ($ real, 2021/22)

Name	Estimated cost uplift	Description
Cyber security	$1.1m-$2.5m per annum (depending on maturity level uplift required. This uplift represents the potential increase above existing activities)	There is a potentially significant increase in operating expenditure required to maintain different levels of cyber security readiness, pending the *Security Legislation Amendment (Critical Infrastructure) Bill 2020.* **This is discussed further below.**
Transmission Ring-Fencing	Unknown	The AER's Electricity Transmission Ring-Fencing Guideline Review may result in additional obligations and operating expenditure. The quantum of these costs will depend on the nature and extent of changes proposed. **This is discussed further below.**
Nature Conservation Act 1992 fees	$1m (2023/24), $70k per annum thereafter	Potential new fees for co-location of assets within national parks. The timing of this new obligation is uncertain and may not arise before the AER's Final Decision in April 2022.
Generator Technical Performance Standards (GTPS)	$63k per annum	Increased costs (above those already realised in 2018-22) related to the provision of operational advice on system-related matters due to the National Electricity Amendment (Managing Power System Fault Levels) Rule 2017 No. 10. This was originally forecast to have a larger impact (~$250k per annum). However further analysis revealed the majority of this cost has been realised in our base year.
Whistle-blower Protections	$150k per annum	Additional administrative and compliance costs related to new whistle-blower legislation under the *Corporations Act 2001.* We decided not to pursue this potential step change as the cost was not considered material.
Modern Slavery Act 2018	$130k per annum	New administrative compliance costs related to the *Modern Slavery Act 2018.* We decided not to pursue this potential step change as the cost was not considered material.

Cyber security

Over the 2023-27 regulatory period, a significant increase in operating expenditure may be required to maintain Powerlink's cyber security maturity. To manage the risks posed by increasing cyber security threats and to ensure an appropriate level of cyber security readiness while maintaining alignment with the voluntary Australian Energy Sector Cyber Security Framework (AESCSF), we anticipate operating expenditure associated with cyber security will be in the range of $1.5m to $2.4m per annum. We will undertake these works as a prudent operator and to appropriately manage our cyber security risks within our forecast operating expenditure for the 2023-27 regulatory period.

In December 2020, the Federal Government introduced the *Security Legislation Amendment (Critical Infrastructure) Bill 2020* to Parliament. If passed, this legislation would establish a new security and resilience regulatory regime on operators of critical infrastructure and we anticipate there would be elevated security obligations and standards on critical infrastructure owners and operators such as Powerlink.

At this stage, we estimate that our costs may increase to a total of between $3.5m to $4.0m (an increase of between $1.1m to $2.5m per annum) if higher levels of readiness than Powerlink's current target are mandated by the Federal Government. Given the uncertainty around the scope and timing of these future formal obligations, we have decided not to include a step change for these costs in our forecast at this time.

In the event that mandatory higher security requirements eventuate during the 2023-27 regulatory period, we aim to absorb this within our total operating expenditure allowance. If associated costs (which may also include capital expenditure costs) are material, we may also need to investigate other options, such as a cost pass through arrangement (refer Chapter 12 Pass Through Events).

AER review of TNSP Ring-Fencing Guideline

The AER's Electricity Transmission Ring-Fencing Guideline Review may result in additional operating expenditure. The quantum of these costs will depend on the nature and extent of any changes to the existing guideline. Given the AER has recently postponed recommencement of the Guideline Review to mid-2021, we intend to reassess this matter following the publication of the AER's Draft Guideline in September 2021.

At that time, there may be a need to seek additional operating expenditure and/or seek a cost pass through arrangement. In the event that costs are minor, we will aim to absorb these within our operating expenditure allowance.

AEMO fees

Implementation of AEMO's National Transmission Planner (NTP) fees were finalised by the AEMC in October 2020. The Rule addressed mechanisms to apply the actionable ISP framework. These fees are developed and applied outside a revenue determination process. As a result, they have not been considered further in our Revenue Proposal.

AEMO also began consultation on its participant fee structures in August 2020, which will apply from 1 July 2021 under the Rules. AEMO has proposed a reallocation of NEM function fees from just generators and market customers to also include TNSPs and DNSPs. Examples of these functions include AEMO's involvement in power system security, reliability and market operation.

We consider that the activities identified by AEMO as being undertaken for TNSPs are actually to meet AEMO's own obligations with respect to power system security. This issue aside and, based on AEMO's budget estimates for 2020/21, we anticipate that we would be subject to an additional $4.0m per annum in AEMO fees. It is not clear at this time how these fees would be recovered from electricity consumers, which could be by way of the newly implemented NTP fee arrangements.

However, for the purposes of our Revenue Proposal, we have not included any adjustment to our forecast operating expenditure to account for these additional fees. We will engage with the AER and our customers further on this matter following AEMO's Final Determination in March 2021.

6.7 Forecast non-controllable other operating expenditure

We have developed category-specific forecasts for the AEMC Levy, 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.

In the normal course of business, we classify our insurance costs (premiums and self-insurance) as non-controllable, other operating expenditure. However, since we published our Expenditure Forecasting Methodology in June 2020 we have decided, for the purposes of forecasting for our Revenue Proposal, to include insurance costs in our base year, rather than as a category-specific forecast.

6.7.1 Insurance

As a business, we take a holistic approach to the identification and management of our risks. We propose to adopt a combination of insurance policies, self-insurance and pass through arrangements in the 2023-27 regulatory period to efficiently manage exogenous risks associated with operating our network to deliver the most cost-effective outcome for customers and Powerlink.

The insurance industry is in a hard phase of the cycle. Current and anticipated volatility in the insurance market has created uncertainty around future costs. We engaged our insurance brokers, Marsh, to provide independent advice on our insurance and risk management approach for the 2023-27 regulatory period. This is provided in Appendix 6.04 Insurance Projections.

To provide our customers and other stakeholders with the opportunity to hear from and speak directly to experts in the global insurance field, we arranged for Marsh to discuss the insurance market with our RPRG. We also held a deep dive workshop in November 2020 which was open to broader stakeholders to discuss the trade-offs between cost and risk and to help inform our considerations and decision-making on insurance cover over the 2023-27 regulatory period and beyond.

The forecasts from Marsh indicate that insurance premiums for our current insurance coverage may increase by $17.0m (41%) in the 2023-27 regulatory period compared to our total actual/forecast insurance premium costs for the 2018-22 regulatory period.

Due to the current and anticipated uncertainty and volatility in the insurance market, we have used the base-step-trend model to forecast our insurance costs for the 2023-27 regulatory period. We also consider this to be the right approach in the context of customer affordability and the current and mid-term economic climate. It will be a challenge for us to manage any difference between our actual insurance costs and the AER's final allowance, and this may involve trade-offs (e.g. between the extent of our levels of cover and reducing other operating expenditure).

Overall, Marsh's total insurance cost forecasts for the 2023-27 regulatory period are $21.3m (49%) higher than the base-step-trend forecasts.

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

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 the majority 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 6.13 outlines our insurance premium cost forecast, trended from the 2018/19 base year expenditure. We have shown this for comparative purposes against the advice we received from Marsh. The data shows that if actual insurance premiums turn out to be consistent with Marsh's forecasts, we may be required to absorb an additional $23.3m within our total forecast operating expenditure over the 2023-27 regulatory period.

Table 6.13: Insurance premiums ($m real, 2021/22)

Insurance premiums	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Base-step-trend forecast	7.0	7.1	7.1	7.1	7.1	**35.6**
Marsh forecast	10.0	10.8	12.1	12.7	13.3	**58.9**
Variance	**3.0**	**3.7**	**5.0**	**5.5**	**6.1**	**23.3**

Self-insurance

Self-insurance costs relate to losses that are below the insurance deductible amounts contained in our insurance portfolio and other minor losses that cannot be insured. We engaged Marsh to review historical levels of these losses and develop a forecast of prudent self-insurance amounts for the 2023-27 regulatory period.

Table 6.14 outlines self-insurance cost forecasts. Again, the forecast has been trended from the 2018/19 base year and compared to the Marsh forecast. In this case, the base-step-trend forecast is $2.0m higher than the estimate prepared by Marsh for the five year period.

Table 6.14: Self-insurance ($m real, 2021/22)

Self-insurance	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Base-step-trend forecast	1.6	1.6	1.6	1.6	1.6	**8.0**
Marsh forecasts	1.2	1.2	1.2	1.2	1.2	**6.0**
Variance	**(0.4)**	**(0.4)**	**(0.4)**	**(0.4)**	**(0.4)**	**(2.0)**

Pass through events

Residual risk events outside our control that cannot be commercially insured or self-insured can potentially be addressed through the cost pass through mechanism in the Rules. Our nominated pass through events are discussed in Chapter 12 Pass Through Events.

6.7.2 AEMC Levy

In 2014, the Queensland Government enacted changes to the *Electricity Act 1994*[27]. Under these changes, 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 cost is currently passed through to Powerlink and we incur this cost as operating expenditure.

AEMC Levy forecasts over the 2023-27 regulatory period have been developed on the basis of a category-specific approach and is shown in Table 6.15. Consistent with our 2018-22 Revenue Proposal, these figures are based on advice from the Queensland Government and reflect the AEMC's forward estimates of its budget up to 2024/25 and an assumed 2.5% annual increase in costs thereafter.

In the first three years of this regulatory period, actual AEMC Levy costs incurred increased significantly and exceeded the AER's allowance by $5.8m (25.7%). Based on our experience to date, we consider that there is a very real risk that outturn costs will again being higher than our proposed forecast for the 2023-27 regulatory period, particularly given the significant energy market reforms being progressed.

Notwithstanding these concerns and consistent with our no real growth and no step change approach, we propose to manage any increases to these costs beyond the forecasts below within our total operating expenditure allowance for the 2023-27 regulatory period.

Table 6.15: AEMC Levy ($m real, 2021/22)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
AEMC Levy	5.9	5.9	5.9	6.0	6.0	**29.7**

6.7.3 Network support

Network support refers to costs associated with non-network solutions used as an efficient alternative to network augmentation. Potential non-network solutions may include local generation, cogeneration, demand side response and services from a Market Network Service Provider (MNSP).

In the 2023-27 regulatory period we anticipate that there may be a need to contract with generators and large load operators to provide a contingency tripping service as part of an upgraded scheme to extend Central Queensland to Southern Queensland (CQ-SQ) transfer limits.

Given the uncertainty around potential costs with no contracts in place at present, and the possibility for emerging energy market dynamics to alter the requirements for network support closer to the time, we have included a $0 network support allowance in our operating expenditure forecast. Any actual network support costs incurred during the 2023-27 regulatory period will be recovered through pass through arrangements (refer Chapter 12 Pass Through Events).

We will review whether an allowance for network support costs should be pursued in our Revised Revenue Proposal if contracts are in place at that time.

6.7.4 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 Network Service Providers (NSP's) 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 9 Rate of Return, Taxation and Inflation).

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

Our operating expenditure forecast reflects a debt raising cost assumption of 8.5 basis points per annum, as shown in Table 6.16. This is based in external advice from Incenta, which is detailed in Appendix 6.05 Benchmark Debt and Equity Raising Costs Report.

Table 6.16: Debt raising costs ($m real, 2021/22)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Debt raising costs	3.5	3.5	3.4	3.3	3.2	**17.0**

6.8 Interaction between forecast capital and operating expenditure

The Rules[28] 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 and reliable 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 operating and capital expenditure. Consistent with our asset management framework, we use life-cycle cost analysis to deliver prudent and efficient outcomes for our customers.

As discussed in Chapter 2 Business and Operating Environment, forecast demand growth is expected to be relatively flat over the 2023-27 regulatory period in line with the limited demand growth seen over the 2018-22 regulatory period. The ratio of operating and capital expenditure is therefore expected to be similar between the two regulatory periods.

There are several key network and market trends that may impact our combined capital and operating expenditure approach over the 2023-27 regulatory period.

A significant contributor to forecast network non load-driven capital expenditure in the 2023-27 regulatory period is our ageing population of steel lattice transmission towers (refer Chapter 5 Forecast Capital Expenditure). As these steel lattice towers age, the level of corrosion and deterioration reaches a point where actions beyond normal maintenance will be required, which trigger the need for reinvestment works[29]. If reinvestment is delayed, this may result in increased operating expenditure to manage deterioration of asset condition.

At the same time, COVID-19 has impacted the scheduled delivery of some of our capital projects. It has also shifted the balance between operating expenditure categories due to travel and work practice restrictions, as well as delays in procurement of specialised equipment. We will continue to monitor this situation as it evolves and ensure that we continue to operate our network in a prudent and efficient manner, consistent with our regulatory and customer obligations.

Several non-network initiatives within the 2023-27 regulatory period are also expected to involve interaction between capital and operating expenditure activities, as set out below:

- We continue to investigate opportunities to extend the capability of transmission network assets through non-network solutions such as network support. Contracts with generators and large loads may mitigate the power system impact from contingency events and improve power system security, and allow us to deliver additional market benefits without network augmentation.
- Our proposed office refit project will allow us to make more efficient use of our available office space and deploy modern building management systems. This is expected to deliver operating expenditure savings in utilities costs.
- Cyber security is increasingly critical for the safe and secure operation of our network. In the 2018-22 regulatory period, we have undertaken both capital and operating expenditure works to improve our cyber security maturity. We anticipate these works will continue through the 2023-27 regulatory period and may increase in cost and complexity (refer Section 6.6.3).
- Business IT capital expenditure is expected to deliver operating efficiencies, focus IT delivery on better customer outcomes, rationalise systems and facilitate upgrades to specific programs. This may help reduce the operating costs of our IT systems and support increased cyber security through a transition away from outdated operating platforms.

[28] National Electricity Rules, schedule S6A.1, clause S6A.1.3(1).

[29] Reinvestment can involve retiring the asset without replacement if it is no longer required to maintain the prescribed levels of transmission services, life extension of the existing asset, like-for-like replacement of the asset, or replacement with a different asset.

6.9 Summary

We have targeted no real growth in operating expenditure over the 2023-27 regulatory period, compared to actual/forecast underlying operating expenditure over the current 2018-22 regulatory period and no step changes.

Customer feedback on productivity, affordability and the impacts of the current economic climate has been central to the development of our Revenue Proposal. This target will be a challenge for our business, particularly given likely increases to various categories of our operating expenditure. Ultimately, we decided to take up this challenge in the interests of customers and to drive the business harder while continuing to meet our customer and regulatory obligations, with a view to becoming a world-class service provider.

Our approach results in total forecast operating expenditure of $1,029.4m (excluding debt raising costs) and $1,046.4m (including debt raising costs). We consider that this forecast:

- meets the requirements of the Rules and the AER's 2013 Expenditure Forecast Assessment Guideline for Electricity Transmission;
- reflects an efficient level of operating expenditure in line with reduced expenditure over the current regulatory period, supported by an independent assessment of the efficiency of our proposed base year;
- represents a realistic forecast of expenditure for the period, based on minimal forecast demand growth and our close alignment of actual/forecast expenditure in the current regulatory period; and
- is a prudent and efficient forecast that responds to our customers' concerns through a productivity target above the industry average, no proposed step changes, and the potential for us to absorb of the order of $26.1m in cost increases over the 2023-27 regulatory period.

7. Escalation Rates and Project Cost Estimation

7.1 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.

The chapter also explains our approach to estimate the cost of projects included in our capital expenditure forecast and the unit rates used in the Repex Model.

Key highlights:

- As inputs to forecast our capital and operating expenditure, we have used:
  - an average annual growth rate of 0.7% for internal labour costs and 0.7% for external labour costs over the 2023-27 regulatory period. These include Superannuation Guarantee (SG) increases of 0.5% in the years 2021/22 to 2025/26; and
  - an annual increase in the costs of materials based on the Consumer Price Index (CPI). This results in a zero real (or inflation-adjusted) increase.
- Our updated unit rates in the Repex Model have increased by an average nominal rate of 2.5% per annum from the unit rates provided in our 2018-22 Revenue Proposal.
- We sought independent advice from BIS Oxford Economics (BISOE) on wage growth forecasts and GHD Advisory on unit rates to inform our respective positions.
- We have applied our standard internal cost estimating approach for bottom-up estimates of capital projects. In 2018-22, we transitioned to a new cost estimating approach that better aligns with international standards.

7.2 Regulatory requirements

The National Electricity Rules (the Rules)[1] 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.

7.3 Cost escalation overview

We have adopted real input cost changes for internal labour, external labour and materials as presented in Table 7.1. Our forecasts for the remaining two years of the current 2018-22 regulatory period are also shown for completeness.

Table 7.1: Real input price growth (% per annum)

	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	Average 2023-27
Internal Labour	0.5	0.6	0.4	0.5	0.9	1.1	0.7	0.7
External Labour	(0.5)	0.4	0.3	0.5	0.8	1.2	0.6	0.7
Materials	-	-	-	-	-	-	-	-

Source: BISOE, Deloitte Access Economics (DAE).

[1] National Electricity Rules, clauses 6A.6.6(c) and 6A.6.7(c).

7.4 Cost escalation approach

A summary of the approach used to determine our cost escalation forecasts is provided in Table 7.2.

Table 7.2: Approach used to forecast cost escalation

Escalation factor	Basis of forecast
Internal Labour	Simple average of two forecasts over the 2023-27 regulatory period: • BISOE - Electricity, Gas, Water and Waste Services (EGWWS) Wage Price Index (WPI) for Queensland; and • Deloitte Access Economics (DAE) National Utilities WPI forecast prepared for the AER(1). The SG increase of 0.5% was then added for the years 2021/22 to 2025/26(2).
External Labour	Simple average of two forecasts over the 2023-27 regulatory period: • BISOE Construction WPI for Queensland; and • DAE National All Industries WPI forecast prepared for the Australian Energy Regulator (AER)(1). The SG increase of 0.5% was then added for the years 2021/22 to 2025/26.
Materials	CPI – assumed forecast of 2.25%.

(1) Deloitte Access Economics, Wage Price Index forecasts prepared for the Australian Energy Regulator, August 2020 – as presented in the Draft Decisions for the Victorian Distribution Network Service Providers - AusNet Services, Jemena, United Energy, CitiPower and Powercor in September 2020.

(2) The minimum employer superannuation contribution will increase by 0.5% each year from 1 July 2021 to 1 July 2025[2].

We applied a simple average of two independent forecasts of the WPI for relevant employment sectors for the 2023-27 regulatory period. This is consistent with the AER's approach[3]. We then added SG increases of 0.5% for the years 2021/22 to 2025/26, which is also consistent with the AER's approach in recent determinations[4].

We engaged BISOE to provide an independent WPI forecast specific to Queensland's business environment and economic outlook. BISOE is a leading provider of industry research, analysis and forecasting services. BISOE's wage growth forecasts for Queensland and nationally leverage their comprehensive knowledge of the Australian economy and industrial sectors, to link labour market conditions to overarching macroeconomic and regional drivers. BISOE's forecast was developed in October 2020 and took into account the impact of COVID-19. BISOE's report is provided in Appendix 7.01 Labour Cost Escalation Forecasts to FY2027 Report.

BISOE provided WPI forecasts over the seven year period from 2020/21 to 2026/27. This captures the last two years of our current 2018-22 regulatory period and the five years of our 2023-27 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.

Consistent with the approach it has applied in its recent regulatory determinations, we anticipate that the AER will engage DAE to provide alternative WPI forecasts for our Draft Decision. In the interim, we have used the most recent available and relevant DAE forecast. That is, the National Utilities and National All Industries forecasts that were prepared for the AER's Victorian Distribution Network Service Providers (DNSPs) Draft Decisions released in September 2020[5].

We propose a real price growth for materials of zero in our expenditure forecasts for the 2023-27 regulatory period. This reflects the expectation that materials costs will increase in line with CPI and is consistent with other recent regulatory determinations[6].

Further detail on each approach is provided below.

2 *Superannuation Guarantee (Administration) Act 1992*, as amended by the *Minerals Resource Rent Tax Repeal and Other Measures Act 2014*.

3 Final Decision, SA Power Networks Distribution Determination 2020-2025: Attachment 6 Operating Expenditure, Australian Energy Regulator, June 2020, pages 6-14. This approach was also applied to Final Decisions published in 2020 for Energex, Ergon Energy, DirectLink and Jemena Gas Networks.

4 Draft Decision, AusNet Services Distribution Determination 2021-26: Attachment 6 Operating Expenditure, Australian Energy Regulator, September 2020, page 48. This approach was also applied consistently to Draft Decisions published in September 2020 for Jemena, United Energy, CitiPower and Powercor.

5 Draft Decisions for AusNet Services, Jemena, United Energy, CitiPower and Powercor, Australian Energy Regulator, September 2020.

6 Final Decisions for Energex, Ergon Energy and SA Power Networks, Australian Energy Regulator, June 2020.

7.4.1 Internal labour price growth

We used the EGWWS WPI forecast for Queensland provided by BISOE as one of the two WPI forecasts for internal labour. We consider that this is an appropriate forecast as it specifically relates to Queensland based EGWWS ('utilities') companies and the specialised resources that the sector includes.

BISOE found that the utilities sector has been impacted less than most employment sectors by the economic consequences of the COVID-19 pandemic[7]. It attributes this to the essential nature of the services that the utilities sector provides, and the need to retain skilled labour. Further, BISOE expect demand for such skilled labour to increase over the forecast period.

> *With strong competition for similarly skilled labour from the mining and construction industries, firms in the utilities sector will need to raise wages to attract and retain workers. In other words, the mobility of workers between the EGWWS, mining and construction industries means that demand for workers in those industries will influence employment, the unemployment rate and hence spare capacity in the EGWWS labour market. Businesses will find they must 'meet the market' on remuneration in order to attract and retain staff and we expect wages under both individual arrangements and collective agreements to increase markedly over the FY24 to FY26 period*[8].

In the absence of a recent and appropriate WPI forecast from DAE for the utilities sector in Queensland, we used the National Utilities WPI forecast provided to the AER for the Victorian DNSPs[9] as a second WPI forecast for internal labour. This presented DAE's forecast of the national average annual wage growth in the utilities sector to 2025/26. To derive the wage growth for the final year of our 2023-27 regulatory period from the DAE forecast, for simplicity we maintained the growth to that forecast for 2025/26. We considered that an alternative approach to extrapolating the forecast, such as linear regression, would overstate the final year forecast due to the negative real growth in previous years of the DAE forecast.

We recognise that this forecast may change by the time the AER publishes its Draft Decision on our 2023-27 Revenue Proposal in September 2021, especially if the uncertainty and impacts of COVID-19 are prolonged. However, we expect the AER will substitute its updated forecasts from DAE at that time.

Our real internal labour price growth calculation is included in Table 7.3 at the end of this section.

7.4.2 External labour price growth

We have used the Construction WPI forecast for Queensland provided by BISOE as one of the two WPI forecasts for external labour. We consider this to be an appropriate forecast as it reflects locational factors and recognises that the labour market for specialised resources employed in high voltage transmission works accessed by contractors is not constrained to Queensland.

BISOE expects construction activity across Australia to increase consistently from 2022/23, with activity peaking in 2024/25. It expects that this increased construction activity will result in the re-emergence of skilled labour shortages and competition for scarce labour, particularly from the mining and construction sectors, placing significant upward pressure on external labour required to deliver our capital works programme in the 2023-27 regulatory period[10].

> *Australian construction wages are expected to pick up over FY23 and strengthen appreciably over FY24 to FY26, particularly as construction activity levels surpass the previous highs of FY18 and skills shortages begin to manifest. The increases in construction activity from FY22 will be driven by the recovery in residential building activity which is expected to rise out of its trough from FY23, while higher levels of non-dwelling building and rising engineering construction will also underpin higher wages. Engineering construction driven by a new wave of mining investment and a plethora of publicly funded transport infrastructure projects (particularly in the eastern states of the nation). Declines in construction activity over FY26 to FY27, coupled with a general weakening across overall labour markets will then cause construction wages growth to ease in FY27.*
>
> *Given that the growth in construction activity in Queensland is forecast to be much stronger than the national average over the next three years, we expect Queensland construction wages to outpace the national average over FY22 and FY23. Thereafter, we expect it will match the national average to FY27*[11].

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[7] Labour Cost Escalation Forecasts to FY2027, BIS Oxford Economics, November 2020, page 28.

[8] *Ibid*, pages 3-4.

[9] Draft Decisions for AusNet Services, Jemena, United Energy, CitiPower and Powercor, Australian Energy Regulator, September 2020.

[10] Labour Cost Escalation Forecasts to FY2027, BIS Oxford Economics, November 2020, pages 30-31.

[11] *Ibid*, pages 4-5.

This growth in construction activity is further exacerbated by the proposed electricity transmission interconnector investments identified in Australian Energy Market Operator's (AEMO's) 2020 Integrated System Plan (ISP) and the ongoing significant investment in renewable generation throughout Queensland. This will lead to additional competition for scarce skilled labour.

BISOE also warn that the skills shortage to service these sectors will not be resolved in the near term. BISOE forecast a shortfall in the number of TAFE graduates required to meet the attrition rate of the relevant skilled trade categories, while the suspension of skilled immigration prevents this shortfall from being addressed by migration[12].

Again, as a more recent and appropriate WPI forecast from DAE is not yet available, we used the National All Industries WPI forecast provided to the AER for the Victorian DNSPs[13] as the second WPI forecast for external labour. Similar to the internal labour forecast, for simplicity we maintained the growth for 2026/27 to that forecast for 2025/26.

We recognise this forecast will be substituted with a revised forecast published with the AER's Draft Decision.

We note the AER has applied no real growth to external labour in recent regulatory decisions[14]. External labour growth in line with CPI does not reflect the contracting environment that we experience, and does not appear to recognise the increasing competition for specialist skilled labour in the transmission sector. We encourage the AER to apply a construction sector specific WPI forecast to inform external labour wage growth forecasts for our 2023-27 regulatory period. Alternatively, an All Industries WPI forecast would at least partly recognise these factors and be consistent with the approach the AER applied to underpin expenditure allowances for our current regulatory period. These constraints are discussed in detail in BISOE's report[15].

Our real external labour price growth calculation is included in Table 7.3 at the end of this section.

Superannuation Guarantee increase

The Australian Government committed to increasing the SG such that the minimum employer superannuation contribution will increase from the current 9.5% of an employee's ordinary time earnings to 12.0%, increasing by 0.5% each year from 1 July 2021 to 1 July 2025[16].

Although the statutory obligation to pay the SG rests with the employer, BISOE and DAE have both stated that they expect a proportion of the SG increase will be passed on by employers to employees in the form of reduced wage growth. As a result, this assumption has been included in their respective WPI forecasts[17].

The WPI published by the Australian Bureau of Statistics (ABS) excludes employer contributions to superannuation and other non-direct employment costs[18]. BISOE has confirmed that their WPI forecasts specifically exclude such employer 'on costs'[19]. This was also confirmed by DAE for the AER Draft Decisions for the Victorian DNSPs in September 2020[20]. Hence, in line with recent regulatory decisions, we have added the 0.5% employer cost arising from the SG to our internal and external labour forecasts for the five years from 2021/22 to 2025/26[21].

We note that the increase to the SG that is due to take effect from 1 July 2021 remains subject to Federal Government consideration[22], largely due to the current economic climate and the potential impacts of the SG increase on wage growth. The wage growth assumptions and forecasts by both BISOE and DAE reflect the cost of the SG increase being partially passed through to employees through lower wage growth than would otherwise be expected. Therefore, in the event of the SG increase being deferred, the wage growth assumptions and forecasts would need to be revised. The removal of the SG increase from internal and external labour forecasts alone would not be appropriate.

12 *Ibid*, pages 31-32.

13 Draft Decisions for AusNet Services, Jemena, United Energy, CitiPower and Powercor, Australian Energy Regulator, September 2020.

14 Draft Decision, AusNet Services Distribution Determination 2021 to 2026, Attachment 5 Capital Expenditure, Australian Energy Regulator, September 2020, pages 17-18.

15 Labour Cost Escalation Forecasts to FY2027, BIS Oxford Economics, November 2020, pages 30-32 and pages 35-37.

16 *Superannuation Guarantee (Administration) Act 1992*, as amended by the *Minerals Resource Rent Tax Repeal and Other Measures Act 2014*.

17 For a detailed description of how BISOE allowed for this in their WPI forecasts, see Labour Cost Escalation Forecasts to FY2027, BIS Oxford Economics, November 2020, pages 23-24.

18 Wage Price Index: Concepts, Sources and Methods, Australian Bureau of Statistics, November 2012, Paragraph 9.3 (ABS catalogue no. 6351.0.55.001).

19 Labour Cost Escalation Forecasts to FY2027, BIS Oxford Economics, November 2020, page 23.

20 Impact of changes to the superannuation guarantee on forecast labour price growth, Deloitte Access Economics, July 2020.

21 Draft Decision, AusNet Services Distribution Determination 2021-26: Attachment 6 Operating Expenditure, Australian Energy Regulator, September 2020, page 48. This approach was also applied consistently to Draft Decisions published in September 2020 for Jemena, United Energy, CitiPower and Powercor.

22 Press Conference, Prime Minister of Australia, https://www.pm.gov.au/media/press-conference-1.

Table 7.3: Real labour price growth (% per annum)

	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	Average 2023-27
Internal labour								
BISOE EGWWS WPI - Queensland	0.6	0.8	0.6	0.5	0.8	0.8	0.9	0.7
DAE Utilities WPI - National	0.4	(0.5)	(0.8)	(0.5)	(0.1)	0.5	0.5	(0.1)
Average (excluding SG)	**0.5**	**0.1**	**(0.1)**	**0.0**	**0.4**	**0.6**	**0.7**	**0.3**
SG increase	-	0.5	0.5	0.5	0.5	0.5	-	
Average (including SG)	**0.5**	**0.6**	**0.4**	**0.5**	**0.9**	**1.1**	**0.7**	**0.7**
External labour								
BISOE Construction WPI – Queensland	(1.2)	0.2	0.2	0.2	0.6	0.6	0.5	0.4
DAE All Industries WPI – Aus	0.2	(0.5)	(0.6)	(0.3)	0.1	0.7	0.7	0.1
Average (excluding SG)	**(0.5)**	**(0.1)**	**(0.2)**	**0.0**	**0.3**	**0.7**	**0.6**	**0.3**
SG increase(1)	-	0.5	0.5	0.5	0.5	0.5	-	
Average (including SG)	**(0.5)**	**0.4**	**0.3**	**0.5**	**0.8**	**1.2**	**0.6**	**0.7**

(1) The minimum employer superannuation contribution will increase by 0.5% each year from 1 July 2021 to 1 July 2025[23].

Source: BISOE, DAE, Australian Taxation Office (ATO)

7.4.3 Real materials price growth

We propose a real price growth for materials of zero in our expenditure forecasts for the 2023-27 regulatory period. This reflects the expectation that materials costs will increase in line with CPI and is consistent with other recent regulatory determinations[24].

Under current economic conditions, which include historical low levels of inflation and the impacts of COVID-19, it may be appropriate to apply materials cost escalators above CPI. We have chosen not to do this due to the uncertainty that exists in any alternative (non-CPI) materials forecast.

7.5 Repex Model unit rates

We have used a calibrated version of the AER's Repex Model, complemented by more detailed bottom-up analysis for significant projects, to forecast our non load-driven network capital expenditure (refer Chapter 5 Forecast Capital Expenditure).

We have developed cost estimates to establish unit rates for each of the asset types used in the Repex Model. To do this, we:

- prepared a cost estimate for each asset type based on that single asset being delivered as a stand-alone project;
- considered the opportunities to coordinate reinvestment works to form larger projects to extract economies of scale, which reduces the per unit project management, design and commissioning costs and reflects our standard delivery approach; and
- applied an efficiency factor based upon a standard package of works for each individual type of asset and the opportunity to realise efficiencies during delivery, such as reinvestment in four primary plant bays at a substation of similar condition.

[23] *Superannuation Guarantee (Administration) Act 1992*, as amended by the *Minerals Resource Rent Tax Repeal and Other Measures Act 2014*.

[24] Final Decisions for Energex, Ergon Energy and SA Power Networks, Australian Energy Regulator, June 2020.

Based on this approach, our updated unit rates have increased by an average nominal rate of 2.5% per annum from the unit rates applied in our Revenue Proposal for the 2018-22 regulatory period.

7.5.1 Validation of Repex Model unit rates

To validate the Repex Model unit rates we compared the rates to contracted costs and outturn costs of capital projects we have undertaken.

We also engaged GHD to provide an independent expert opinion of a reasonable industry benchmark cost for each of the unit rates used in the Repex Model. We have compared our unit rates to those provided by GHD and found them to be prudent and efficient. On average, our unit rates are 10% less than the equivalent GHD rates.

While there are some variances in specific unit rates contained in GHD's report, these can largely be explained by differences in the underlying assumptions of the unit rates. In particular, the differences in the unit rates to replace primary plant are driven by an alternative approach to how costs of the full-bay replacement are assigned to each individual unit. When the individual unit rates are combined, the resulting full-bay cost from GHD is within the stated estimated accuracy range of Powerlink's unit rate.

We consider the unit rates applied in the Repex Model are realistic and generate a reasonable estimate of forecast costs.

GHD's report is provided in Appendix 7.02. Details of our unit rates, our approach to estimating the unit rates and the comparison to GHD's benchmark unit costs are included in Appendix 7.03 Cost Estimating Methodology. Note that all GHD and Powerlink unit rates provided to the AER are market sensitive and therefore commercial-in-confidence. As a result, they have been treated as confidential.

7.5.2 Reconciliation between Category Analysis RIN Return and Repex Model unit rates

The unit rates adopted in the Repex Model differ from those reported in our annual Category Analysis Regulatory Information Notice (CA RIN) and Reset RIN returns due to three factors:

- the Repex Model unit rates include a corporate overhead (indirect cost) allocation. The AER requires annual CA RIN and Reset RIN data to be estimated on an 'unburdened' basis. That is, any allocation for corporate overheads must be excluded;
- unit rates for new assets derived from the CA RIN information do not include costs to modify or enhance an existing asset or costs incurred after the asset has been capitalised[25]. For example, when a new replacement substation asset is commissioned and work on an existing asset at a remote location is required, the cost of the complementary works is capitalised into the existing asset's value, not the new asset's value; and
- Repex Model unit rates have been developed using bottom-up estimates. This differs from CA RIN return unit rates that are developed by disaggregating project costs to an asset level (top-down). The assumptions applied in the disaggregation of the CA RIN unit rates do not align with the requirements for forecast unit rates applied in the Repex Model.

The impact of these differences is that the unit rates reported in our annual CA RIN and Reset RIN returns will tend to be lower than our observed project costs.

To forecast our reinvestment capital expenditure for the 2023-27 regulatory period using the Repex Model, we consider it appropriate to capture the costs identified above in the unit cost input module.

7.6 Cost estimates

Cost estimates are developed from a scope of work based upon an identified network need. Identified network needs may be triggered, for example, by growth in customer demand exceeding existing network capacity, the condition or obsolescence of existing network assets or the need to maintain network performance standards.

Throughout the stages of investment development and approval, a number of options will be considered, including non-network options where identified. The technically feasible options will be scoped and estimated to ensure the most cost-effective solution is chosen. In the normal course of business, we develop different types of capital and operating project cost estimates to assess options under the public Regulatory Investment Test for Transmission (RIT-T) and for input to internal governance documentation to support project approvals.

The type and level of accuracy of the estimate will vary depending on the stage in the investment development life-cycle. Typically, the more developed the need, justification and scope of works, the more detailed and accurate the cost estimate.

[25] Category Analysis Regulatory Information Notice 2019/20, Basis of Preparation, Powerlink Queensland, October 2020.

The different approach to project cost estimates and escalators applied is summarised in Table 7.4.

Table 7.4: Project cost estimates and escalators

Phase of investment development	Description	Basis of cost estimate
Project in construction	Already received full financial approval consistent with corporate governance framework.	Business-as-usual estimates, typically detailed bottom-up (Project Proposal) or contracted prices where available.
Confirmed need	Projects not yet approved but the need has been confirmed and options are being assessed in preparation for seeking financial approval.	Combination of: • business-as-usual estimates, typically detailed bottom-up (Project Proposal) or contracted prices where available; and • concept estimates that adopt real labour cost escalators and CPI for materials cost escalation;
Future need	Based on normal business practices there is an expected future need. However, specific project details are not yet finalised or ready to seek financial approval.	Combination of: • concept estimates that adopt real labour cost escalators and CPI for materials cost escalation; • unit rates for reinvestments. These are inputs to the Repex Model. The model also adopts the real labour cost escalators and CPI for materials cost escalation; and • historical trends in expenditure.

During the current 2018-22 regulatory period we implemented a change to how we prepare preliminary estimates. We previously based our preliminary estimates on established estimating building-blocks, called Base Planning Objects. This was similar to the unit rate approach used in the Repex Model. We have transitioned to a cost estimating approach that is consistent with international recommended practice[26].

Our current cost estimation approach is based on an assessment of the resources required (labour, equipment, materials and sub-contracts) to complete each item of work specific to the project scope and design. We also identify and cost items peculiar to the project site to account for project-specific site conditions.

We consider that our current approach better aligns with international recommended practice. We will continue to update our approach as necessary to ensure our cost forecasts remain appropriate and reflective of efficient costs.

7.7 Summary

We have developed our real labour price growth escalators for the 2023-27 regulatory period based on a simple average of two independent forecasts from BISOE and DAE.

We used our internal cost estimating process to develop unit rates for reinvestment works that are reflective of our delivery approach, and tested these against independent benchmark costs from GHD.

We have developed our project cost estimates in line with international recommended practice.

26 Association for the Advancement of Cost Engineering (AACE International) Recommended Practice No. 18R-97.

8. Regulatory Asset Base

8.1 Introduction

This chapter outlines Powerlink's approach to calculate our opening Regulatory Asset Base (RAB) as at 1 July 2022 and our forecast RAB for each year of the 2023-27 regulatory period.

Key highlights:

- Our opening RAB as at 1 July 2022 is forecast to be $6,958.4m ($ nominal).
- The RAB is forecast to decrease by $19.4m in nominal terms and by $749.6m in real terms over the 2023-27 regulatory period[1]. The main driver for the real decline is a combination of lower capital expenditure in the forecast low demand growth environment and a higher depreciation profile.
- We propose to transfer $2.0m of non-prescribed assets into the RAB at 30 June 2022.
- We propose to remove $4.4m of prescribed assets from our RAB at 30 June 2022.
- The closing RAB as at 30 June 2027 is forecast to be $6,939.0m ($ nominal).
- During the current 2018-22 regulatory period, our RAB is forecast to decrease by $111.0m in nominal terms and by $621.9m in real terms[2].
- Our declining RAB profile since 2014/15 reflects our prudent asset management and reinvestment approach. In particular, where investment is required to address a network need, we do not necessarily replace like-for-like.

8.2 Regulatory requirements

The National Electricity Rules (the Rules)[3] set out how we must establish the opening value of our RAB. We are also required to provide the calculation of the RAB for each year of the current, 2018-22 regulatory period[4]. This is done using the Australian Energy Regulator's (AER's) 2020 Roll Forward Model (RFM) (Version 4).

In relation to additions to the RAB, the Rules[5] 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 used for the provision of prescribed transmission services.

The Rules[6] also provide 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[7] 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.

8.3 Our approach

We established the opening value of our RAB and rolled forward the value of that RAB in each year of the regulatory period consistent with the Rules[8].

We used the AER's 2020 RFM to establish the opening value at 1 July 2022 and the AER's 2019 Post-Tax Revenue Model (PTRM) (Version 4) to calculate the forecast RAB for the 2023-27 regulatory period.

We also propose to change to year-by-year depreciation tracking (refer Chapter 10 Depreciation) and have used the AER's 2020 Depreciation Tracking Module (Version 1).

Prior to the AER's Final Decision we will update our forecast opening RAB as at 1 July 2022 for 2020/21 actuals and, consequently, our forecast RAB roll forward for the 2023-27 regulatory period.

8.4 Opening RAB as at 1 July 2022

To establish the forecast opening RAB as at 1 July 2022 we adjust the opening RAB as at 1 July 2017 (refer Table 8.1).

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1 Based on a comparison of 1 July 2022 opening RAB to 30 June 2027 closing RAB.
2 Based on a comparison of 1 July 2017 opening RAB to 30 June 2022 closing RAB.
3 National Electricity Rules, schedule 6A.2, clause S6A.2.1(f).
4 National Electricity Rules, clause 6A.6.1 and schedule 6A.1, clause S6A.1.3(5).
5 National Electricity Rules, schedule 6A.2, clause S6A.2.1(f)(8).
6 National Electricity Rules, clause 6A.6.1(a).
7 National Electricity Rules, schedule 6A.2, clause S6A.2.1(f)(6)
8 National Electricity Rules, schedule 6A.2, clause S6A.2.1(f).

Table 8.1: Establishment of opening RAB as at 1 July 2022 ($m nominal)

	2017/18	2018/19	2019/20	2020/21 (forecast)	2021/22 (forecast)
Opening RAB	7,069.4	7,094.5	7,105.5	7,103.2	7,003.7
Capital expenditure as incurred(1)	151.4	170.5	170.1	179.5	205.0
Regulatory depreciation(2)	(126.3)	(159.5)	(172.4)	(279.0)	(246.5)
Closing RAB	7,094.5	7,105.5	7,103.2	7,003.7	6,962.2
Difference between forecast and actual capital expenditure in 2016/17					(4.5)
Return on capital for the difference between forecast and actual expenditure 2016/17					(1.2)
Final year asset adjustment					2.0
Opening RAB as at 1 July 2022					**6,958.4**

(1) Net of disposals, adjusted for inflation and one-half Weighted Average Cost of Capital (WACC) allowance[9]. The roll forward also reflects forecast capitalised movements in provisions.

(2) Depreciation is based on forecast depreciation as approved by the AER for the 2018-22 regulatory period and is net of indexation applied to the RAB.

8.5 Forecast RAB for the 2023-27 regulatory period

The forecast RAB for the 2023-27 regulatory period applies the opening RAB at 1 July 2022, as calculated above, and is adjusted as shown in Table 8.2.

Table 8.2: Forecast RAB roll forward 2023-27 regulatory period ($m nominal)

	2022/23	2023/24	2024/25	2025/26	2026/27
Opening RAB	6,958.4	6,985.4	7,025.2	7,004.2	6,973.4
Capital expenditure, as incurred(1)	196.2	220.1	168.6	166.9	172.4
Regulatory depreciation	(169.2)	(180.3)	(189.6)	(197.7)	(206.9)
Closing RAB	**6,985.4**	**7,025.2**	**7,004.2**	**6,973.4**	**6,939.0**

(1) Net of disposals, adjusted for inflation and one-half WACC allowance. The roll forward also reflects forecast capitalised movements in provisions

8.6 RAB additions and removals

Additions

The Rules[10] 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 used for the provision of prescribed transmission services.

In December 2020, we flagged up to an estimated value of $50.0m of potential additions to our RAB to our customers, the AER and the AER's Consumer Challenge Panel (CCP23).

We have assessed these potential asset transfers and have included a value of $2.0m in the closing RAB at 30 June 2022 in our Revenue Proposal. This amount reflects the portion of non-prescribed assets that provide shared network services. In determining an appropriate transfer value, key consideration has been given to the Rules requirements, whether the initial investment has already been recovered and the forecast impact on customers.

We estimate 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 2023-27 regulatory period.

[9] The Post-Tax Revenue Model (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 Weighted Average Cost of Capital (WACC) is added to compensate for the six-month period before capital expenditure is included in the RAB.

[10] National Electricity Rules, schedule 6A.2, clause 6A.2.1(f)(8).

Powerlink and the AER are also in confidential discussions in relation to an asset transfer matter which arose outside the Revenue Proposal process and was included in the $50.0m estimate above. We intend to resolve this matter prior to the AER's Final Decision on our 2023-27 Revenue Proposal.

Removals

We have removed $4.4m in assets from our RAB which have been repurposed to provide non-prescribed transmission services. This approach ensures that assets that have 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 use of the assets going forward will pay for them.

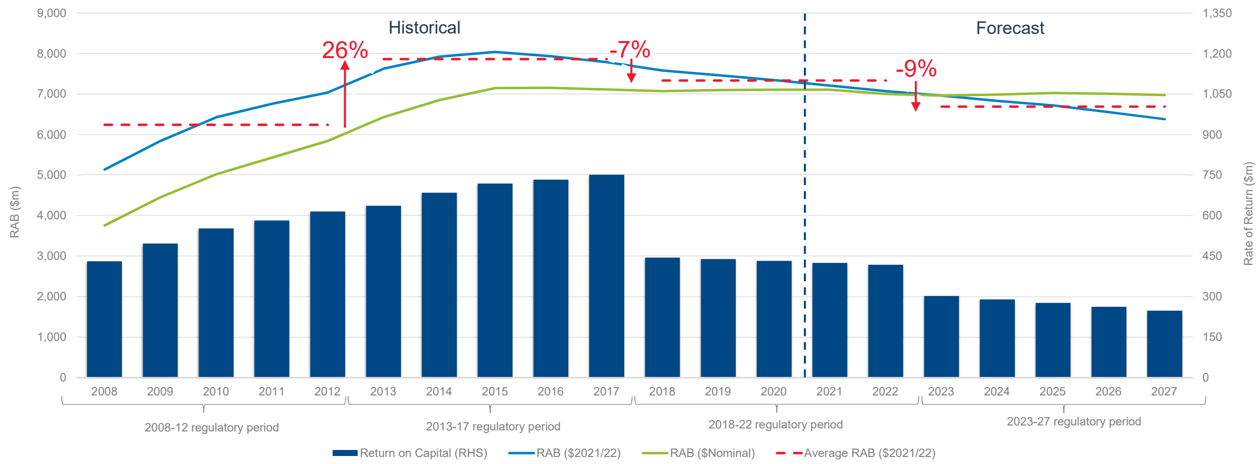
This adjustment has been effected by means of an asset disposal.

Given the commercial-in-confidence nature of additions and removals, further information to support our proposal is provided to the AER on a confidential basis in Appendix 8.01 Regulatory Asset Base Transfers.

8.7 Historical and forecast RAB

Figure 8.1 shows our RAB (in real and nominal terms), over the previous, current and next regulatory periods.

Figure 8.1: Regulatory Asset Base 2007/08 to 2026/27



The chart shows the growth in our RAB as a result of investments in our network over the two previous regulatory periods. In the current regulatory period our RAB has reduced in nominal and in real terms. This trend is forecast to continue through the 2023-27 regulatory period. The change in our RAB reflects an increased depreciation profile and lower capital expenditure in the context of a low load growth environment. Our declining RAB profile since 2014/15 reflects our prudent asset management and reinvestment approach. In particular, where investment is required to address a network need, we consider a range of options and do not necessarily replace like-for-like.

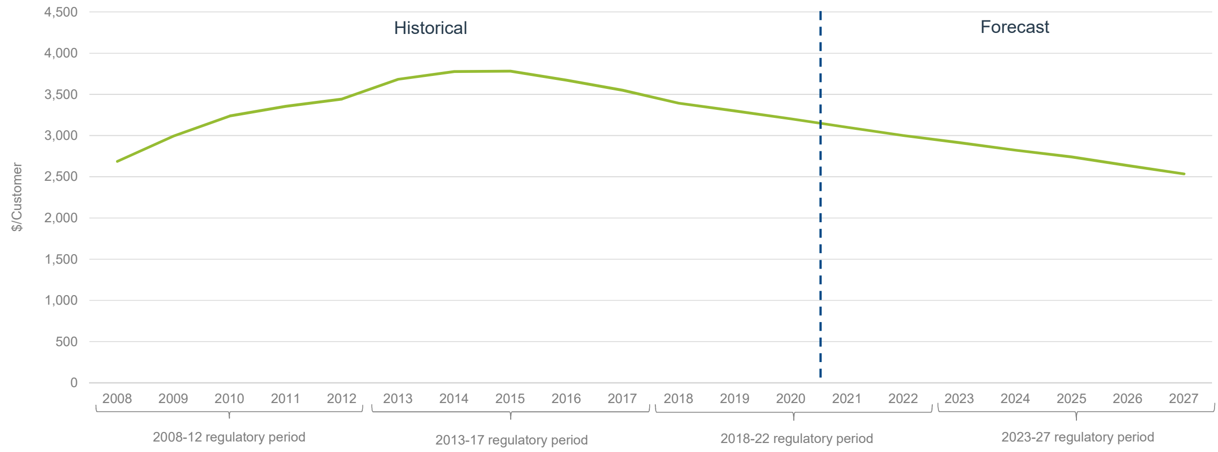
8.7.1 RAB metrics

Our Revenue Proposal Reference Group (RPRG) requested further information about our RAB against key metrics to help inform their views of our approach to asset management. We presented these metrics to the RPRG at our December 2020 meeting.

The two metrics provided are RAB per customer and RAB per MWh. Overall, both measures show a decline since 2014/15, which is favourable to customers.

Our RAB per customer, as shown in Figure 8.2 below, has declined at an average rate of 3% per annum over the current regulatory period, and is forecast to continue to decline at this rate in the 2023-27 regulatory period. This is driven by a combination of a reduction in our RAB and an increase in customer numbers.

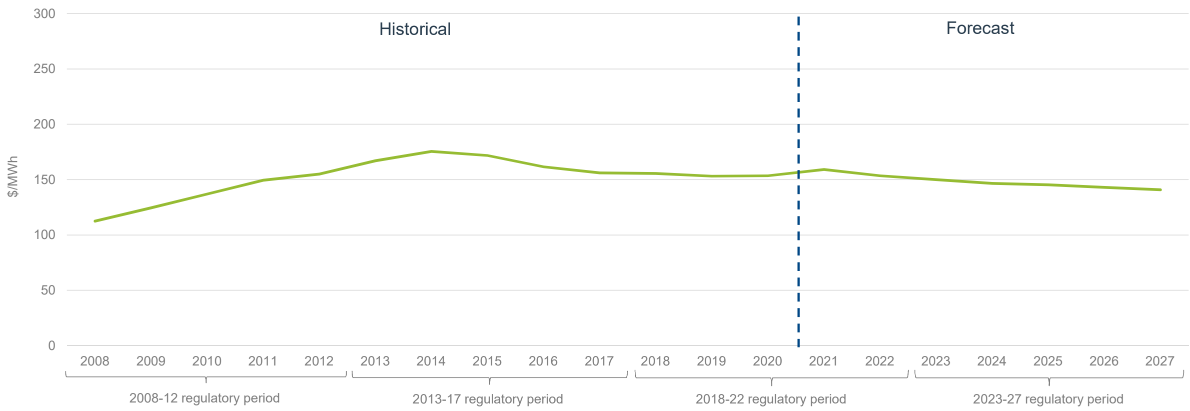
Figure 8.2: RAB per customer ($ real, 2021/22)



Source: Economic Insights, Powerlink[11].

Our RAB per MWh, as shown is Figure 8.3 below, has remained relatively flat during the current regulatory period, and is forecast to decline at a rate of 2% per annum in the 2023-27 regulatory period. This is driven by a reduction in the RAB and flat or declining delivered energy forecasts. The total delivered energy is expected to decline at an average annual rate of 0.7% over the next 10 years[12]. The forecast decline in RAB is in line with the forecast low demand environment.

Figure 8.3: RAB per MWh ($ real, 2021/22)



8.8 Summary

Our opening RAB as at 1 July 2022 is forecast to be $6,958.4m. It is forecast to decrease by $19.4m in nominal terms and by $749.6m in real terms ($ 2021/22) over the 2023-27 regulatory period.

We propose to transfer $2.4m, in net terms, of prescribed assets out of our RAB as at 30 June 2022.

11 Customer numbers sourced from transmission benchmarking data files for the Economic Benchmarking Results for the Australian Energy Regulator's 2020 TNSP Annual Benchmarking Report, Economic Insights, October 2020. Forecast values trended forward and RAB sourced from Powerlink data.

12 2020 Electricity Statement of Opportunities, Australian Energy Market Operator, August 2020.

9. Rate of Return, Taxation and Inflation

9.1 Introduction

This chapter outlines Powerlink's approach to the calculation of the rate of return (also referred to as the Weighted Average Cost of Capital or WACC), taxation and forecast inflation for the 2023-27 regulatory period.

Key highlights:

- We have applied the Australian Energy Regulator's (AER's) binding 2018 Rate of Return (RoR) Instrument. This results in an estimated post-tax nominal RoR of 4.44% for the first year of the 2023-27 regulatory period (2022/23). This comprises:
  - a return on equity of 4.48%; and
  - a return on debt of 4.42%. The return on debt is updated in each year of the regulatory period based on the AER's trailing average approach.
- Our return on capital allowance is the largest component of our building-block revenue. The return on capital represented $2,157.4m (55%) of our total Maximum Allowed Revenue (MAR) approved by the AER in its Final Decision for the 2018-22 regulatory period. It is forecast to be $1,377.7m (41%) of our total forecast MAR for the 2023-27 regulatory period.
- The main driver of our lower RoR is the historically low risk-free rate environment. The AER will update our RoR in its Final Decision for the prevailing risk-free rate at that time and updated trailing average return on debt over our approved averaging periods.
- We have estimated our taxation allowance using the AER's 2019 Post-Tax Revenue Model (PTRM), Version 4. This version of the PTRM gives effect to the changes arising from the AER's 2018 Regulatory Tax Approach Review[1].
- Our forecast for inflation is 2.25%. We have used the AER's current approach for estimating expected inflation[2] as specified in its 2019 PTRM.
- The AER published its Final Position Paper on its review of the treatment of inflation in December 2020[3]. This revised approach does not apply to Powerlink's 2023-27 Revenue Proposal. However, we understand the AER intends to apply its revised approach in our Draft and Final Decisions.

9.2 Regulatory requirements

Under the National Electricity Rules (the Rules)[4], our return on capital allowance is calculated by applying our allowed RoR to the opening value of our Regulatory Asset Base (RAB) in each year of the regulatory period.

Our allowed RoR[5] must be determined on the basis of the current RoR Instrument published by the AER[6]. These calculations are provided in the RoR Model included with our Revenue Proposal[7].

The Rules[8] also require the AER to specify in the PTRM a methodology that is likely to result in the best estimate of expected inflation.

Our corporate tax allowance must be calculated consistent with the Rules[9].

9.3 Rate of return

9.3.1 Overview

Our RoR for the first year of the 2023-27 regulatory period (2022/23) is shown in Table 9.1 and Table 9.2 summarises our forecast RoR for each year. We have included a brief guide to our key inputs and assumptions for our RoR, taxation and inflation in Attachment 1.

[1] Review of Regulatory Tax Approach, Australian Energy Regulator, December 2018.
[2] The geometric average of 10 annual expected inflation rates, using the RBA's forecast of inflation for the first two years and the mid-point of the RBA's inflation target band for the remaining eight years.
[3] Regulatory Treatment of Inflation, Australian Energy Regulator, December 2020.
[4] National Electricity Rules, clause 6A.6.2.
[5] National Electricity Rules, Chapter 10, definition of allowed rate of return.
[6] Rate of Return Instrument, Australian Energy Regulator, December 2018.
[7] National Electricity Rules, schedule 6A.1, clause S6A.1.3(4A).
[8] National Electricity Rules, clause 6A.5.3(b)(1).
[9] National Electricity Rules, clause 6A.6.4.

Table 9.1: Rate of return for 2022/23

Parameter	Estimate
Gearing	60%
Risk-free rate – return on equity	0.82%
Equity beta	0.6
Market risk premium	6.10%
Return on equity	4.48%
Return on debt	4.42%
WACC – post-tax nominal(1)	4.44%

(1) A post-tax nominal vanilla WACC calculation applies a pre-tax cost of debt and post-tax cost of equity.

Table 9.2: Rate of return 2023-27

	2022/23	2023/24	2024/25	2025/26	2026/27
Return on debt	4.42%	4.22%	4.03%	3.83%	3.64%
Return on equity	4.48%	4.48%	4.48%	4.48%	4.48%
WACC – post-tax nominal	4.44%	4.32%	4.21%	4.09%	3.97%

The application of these rates of return to our forecast RAB results in the return on capital allowance outlined in Table 9.3.

Table 9.3: Return on capital allowance ($m nominal)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Return on capital	309.0	302.1	295.6	286.5	277.1	**1,470.3**

9.3.2 Our approach

This section outlines our approach to calculating the RoR, which has the most significant impact on our final approved revenues and ultimately electricity prices. The RoR must be calculated consistent with the AER's 2018 RoR Instrument.

The AER will update the estimated return on equity and return on debt in its Final Decision to reflect our nominated (approved) averaging periods. These periods have been nominated on a confidential basis in Appendix 9.01 Nominated Averaging Periods.

Return on equity

We applied the AER's 2018 RoR Instrument, which results in an estimated return on equity for the 2023-27 regulatory period of 4.48%. For our Revenue Proposal we have adopted a risk-free rate over 20 business days ending 13 November 2020. This is a placeholder estimate only as the AER will calculate its Final Decision on the basis of our nominated period identified on a confidential basis in Appendix 9.01 Nominated Averaging Periods. The parameter values are presented in Table 9.4.

Table 9.4: Return on equity

Parameter	Estimate
Risk-free rate(1)	0.82%
Equity beta	0.6
Market risk premium	6.10%
Return on equity	4.48%

(1) Simple average of the daily ten year Commonwealth Government bond yields (converted to annual effective rates), over an averaging period of 20 business days up to and including the 13 November 2020.

Return on debt

Based on the application of the AER's 2018 RoR Instrument and our ongoing transition to a trailing average return on debt, our indicative return on debt for the first year of the regulatory period (2022/23) is 4.42%[10].

Under the trailing average approach, the AER will update our return on debt in each year of the regulatory period to reflect prevailing rates at that time. For the purpose of our Revenue Proposal, we have assumed that the prevailing return on debt is the same as that applied by the AER in our most recent annual update published in January 2020[11]. This results in the following estimates in Table 9.5.

Table 9.5: Return on debt 2023-27

	2022/23	2023/24	2024/25	2025/26	2026/27
Return on debt	4.42%	4.22%	4.03%	3.83%	3.64%

9.4 Taxation

9.4.1 Overview

Our taxation forecast for the 2023-27 regulatory period is presented in Table 9.6.

Table 9.6: Taxation ($m nominal)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Corporate tax	5.1	1.0	8.0	23.9	24.5	62.5
Value of imputation credits	(3.0)	(0.6)	(4.7)	(14.0)	(14.3)	(36.6)
Taxation	**2.1**	**0.4**	**3.3**	**9.9**	**10.2**	**25.9**

9.4.2 Our approach

We estimate our taxation allowance using the AER's 2019 PTRM (Version 4)[12] based on the expected statutory income tax rate for each year of the regulatory period (30%) less the value of imputation credits (gamma)[13].

The AER's 2019 PTRM also gives effect to two key changes we have adopted from the AER's 2018 Regulatory Tax Approach Review[14], namely:

- adjustments to allow for the immediate expensing of certain costs (our capitalised overhead costs) for taxation purposes. We have used the AER's recommended method of an actuals informed approach to forecast our immediate expensing for the 2023-27 regulatory period; and
- the application of diminishing value depreciation (instead of straight-line) for new assets and capital expenditure (from 1 July 2022), with the exception of buildings, in-house software and equity raising costs. Straight-line depreciation continues to apply for existing assets.

For regulatory and tax depreciation, we propose to change from the use of a Weighted Average Remaining Life (WARL) to the more accurate year-by-year depreciation tracking (refer Chapter 10 Depreciation). The movements in the taxation forecast over the 2023-27 regulatory period reflect the transitional impact of moving to the year-by-year approach.

Consistent with the AER's 2018 RoR Instrument, we have adopted:

- a value of 0.585 to estimate the value of imputation credits (gamma); and
- a statutory tax rate of 30% per year.

[10] The Australian Energy Regulator (AER) approved our transition to a trailing average return on debt in its Final Decision for the 2017-22 regulatory period. The transition is occurring over 10 years and the full transition will be completed in the final year of the 2023-27 regulatory period, ie. 2026/27.

[11] Powerlink – Determination 2017-22 Update Return on Debt 2020-21, Australian Energy Regulator, January 2020.

[12] The Post-Tax Revenue Model (PTRM) determines notional taxable income and tax payable, accounting for deductions for tax depreciation calculated from the Tax Asset Base.

[13] National Electricity Rules, clause 6A.6.4.

[14] Regulatory Tax Approach Review, Australian Energy Regulator, December 2018.

Immediate expensing of capital expenditure

Our forecast of immediately deductible capital expenditure is based on actual immediate deductions of capitalised overheads over previous years. We confirm that we do not intend to change our current tax policy of immediately expensing capital expenditure.

Diminishing value depreciation

We have adopted the diminishing value (DV) method for tax depreciation for all new capital expenditure, with the exception of buildings and in-house software. We confirm that the forecast capex for buildings and in-house software satisfies the relevant definitions under the *Income Tax Assessment Act 1997* (ITAA) and will continue to be depreciated using the straight-line method over the 2023-27 regulatory period.

9.5 Forecast inflation

Our forecast inflation is 2.25%. For the purpose of our Revenue Proposal we are required to apply the AER's current approach to inflation specified in its 2019 PTRM, which estimates inflation using the Reserve Bank of Australia's (RBA's) forecast for the first two years and the mid-point of the RBA's inflation target band for the remaining eight years.

The AER released its Final Position Paper in December 2020[15] on the regulatory treatment of inflation. This has resulted in a change to the approach used to estimate the inflation forecast for future revenue determinations. The AER issued an amended PTRM to reflect its revised approach in December 2020 for consultation and intends to publish its final PTRM by April 2021.

We understand that the AER will apply its revised approach and amended PTRM in its Draft and Final Decisions on our Revenue Proposal.

Our Customer Panel requested information on the indicative impact of the AER's revised inflation approach to understand the implications for customers. Our estimate of inflation using the AER's revised method is 1.80% (versus 2.25% under the current method). In terms of MAR, the indicative impact of this lower inflation forecast over the 2023-27 regulatory period would be an increase of approximately $170.0m.

9.6 Summary

Our RoR and taxation allowance aligns with the relevant regulatory requirements (i.e. the AER's 2018 RoR Instrument and 2019 PTRM (Version 4)). We have used the AER's current approach to forecast inflation.

An overview of the key estimates for each element of our RoR, inflation and taxation is provided in Table 9.7.

Table 9.7: Rate of return, inflation and taxation estimates

Parameter	Estimate
Risk-free rate – return on equity	0.82%
Market risk premium	6.10%
Equity beta	0.6
Gearing	60%
Return on equity	4.48%
Return on debt	4.42%
WACC – post-tax nominal	**4.44%**
Inflation	**2.25%**
Gamma	**0.585**
Taxation rate	**30%**

15 Regulatory Treatment of Inflation, Australian Energy Regulator, December 2020.

10. Depreciation

10.1 Introduction

This chapter outlines Powerlink's proposed return of capital allowance (also referred to as regulatory depreciation) for the 2023-27 regulatory period. Depreciation is an allowance that enables capital investors to recover their investment over the economic life of the asset.

Key highlights:

- Our proposed regulatory depreciation forecast for the 2023-27 regulatory period is $881.3m. This is $261.2m higher than our allowance for the 2018-22 regulatory period, due to a change in the depreciation forecasting approach, lower forecast inflation reducing the inflation adjustment and an increase in depreciation from the recovery of prior years' indexation. This will be updated by the Australian Energy Regulator (AER) in its Final Decision for the final approved inputs.
- We propose to change our depreciation forecasting method from a Weighted Average Remaining Life (WARL) approach to the more accurate year-by-year depreciation tracking approach. In response to feedback from our customers, we also propose a minor transitional adjustment to smooth the revenue impact of this change.
- We do not propose any accelerated depreciation for the 2023-27 regulatory period.

10.2 Regulatory requirements

We have calculated depreciation consistent with the National Electricity Rules (the Rules)[1]. Depreciation schedules must use a profile that reflects the nature of the asset class over the economic life of that asset class.

10.3 Depreciation forecast

Under the regulatory framework, regulatory depreciation is calculated as straight-line depreciation less the inflation adjustment on the opening Regulatory Asset Base (RAB). Straight-line depreciation is a method of calculating depreciation whereby an asset's value is reduced consistently throughout its useful life. Each year, the opening RAB (or RAB at the start of the relevant financial year) is indexed by inflation to maintain the real value of the RAB over time[2].

Our depreciation forecast for the 2023-27 regulatory period is set out in Table 10.1.

Table 10.1: Forecast regulatory depreciation 2023-27 regulatory period ($m real, 2021/22)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Straight-line depreciation(1)	318.6	322.7	325.1	325.0	325.4	1,616.8
Less inflation(2) adjustment on Opening RAB	(153.0)	(150.2)	(147.8)	(144.1)	(140.3)	(735.5)
Regulatory depreciation	**165.5**	**172.5**	**177.3**	**180.9**	**185.1**	**881.3**

(1) We have adjusted for forecast capital expenditure and asset disposals in each year of the regulatory period. Depreciation is calculated on these adjusted RAB values.

(2) Based on an inflation estimate of 2.25% (refer Chapter 9 Rate of Return, taxation and inflation).

Depreciation is forecast to be $881.3m. This is $261.2m or 42% higher than the approved allowance for the 2018-22 regulatory period. This is due to several key drivers which include:

- the transitional impact from the change to the year-by-year tracking approach, as the remaining lives of existing assets are no longer combined with new assets in the current regulatory period;
- the lower inflation adjustment – which means the RAB is reduced by a lower amount than determined in the AER's 2017 Final Decision on our Revenue Proposal for the current regulatory period; and
- an increase in the depreciation profile associated with the recovery of the indexation on assets over time. Assets are indexed by inflation each year. As their value is depreciated over their useful lives, the depreciation of accumulated indexation increases over time.

[1] National Electricity Rules, clause 6A.6.3.
[2] National Electricity Rules, schedule S6A.2, clause 6A.2.4(c)(4).

This forecast reflects the inputs in our Revenue Proposal and will be updated by the AER in its Final Decision. The updated forecast will reflect any changes that impact the roll forward of our RAB (including forecast capital expenditure and asset disposals), along with the updated inflation forecast.

10.4 Our approach

We have calculated regulatory depreciation as forecast depreciation less the inflation adjustment made to the opening RAB.

We have calculated depreciation consistent with the Rules[3] and relevant Australian Accounting Standards[4]. We used the AER's 2019 Post-Tax Revenue Model (PTRM) (Version 4) to calculate the depreciation forecast for new assets from 1 July 2022 and the AER's 2020 Depreciation Tracking Module (Version 1) for existing assets as at 30 June 2022.

Proposed changes to our approach for the 2023-27 regulatory period are summarised below.

10.4.1 Year-by-year depreciation tracking

We propose to move from a WARL approach to a year-by-year depreciation tracking approach. Both methods meet the requirements of the Rules[5]. The year-by-year tracking approach groups new capital expenditure by asset class, then separately depreciates each class over the approved standard lives. It is therefore more accurate than the WARL approach and ensures that the recovery profile of our costs better reflects the economic lives of our assets. The year-by-year approach has been accepted by the AER in other recent regulatory decisions[6] for these reasons.

We consulted with our Revenue Proposal Reference Group (RPRG) and Customer Panel on the transitional impacts to our customers (i.e. an estimated increase to our revenue in the 2023-27 regulatory period) as a result of this change in approach[7].

The RPRG and Customer Panel recognised the year-by-year approach is more accurate, but expressed concerns over the increase in revenue. Members asked that we consider ways to smooth the revenue impact of the change in approach, potentially across two regulatory periods.

As a result of our investigation, we identified the secondary systems asset class as one of the main contributors to this transitional impact. This asset class has a relatively high value of assets with a short life. We therefore propose a minor adjustment to extend the WARL of the existing secondary systems assets at 30 June 2017 from 9.82 years to 11 years, which will reduce the impact of the change in depreciation approach on customers.

This proposed asset life change responds to feedback from our customers and still results in a WARL that appropriately reflects the economic lives of the underlying assets. We have discussed this approach with AER staff.

We have provided our year-by-year depreciation tracking model with our Revenue Proposal. Further information is included in Appendix 10.01 Depreciation Tracking Approach.

10.4.2 Use of forecast depreciation

The AER determined that it will use forecast depreciation to:

- roll forward the RAB for the 2018-22 regulatory period to establish our opening RAB as at 1 July 2022[8]; and
- establish our opening RAB as at 1 July 2027 for commencement of the 2028-32 regulatory period[9].

10.5 Asset classes and asset lives

The change from WARL to a year-by-year tracking approach means it will no longer be necessary to determine remaining asset lives for the various asset classes. The standard lives we propose to apply to each asset class are shown in Table 10.2. We propose to apply the same standard asset lives for the 2023-27 regulatory period as applied in the current regulatory period.

3 National Electricity Rules, clause 6A.6.3.
4 Australian Accounting Standard AASB 116 Property, Plant and Equipment.
5 National Electricity Rules, clause 6A.6.3(b).
6 Draft Decisions for United Energy, AusNet Services, Jemena, CitiPower and Powercor, Australian Energy Regulator, September 2020.
7 Presentation and minutes of the June 2020 Revenue Proposal Reference Group (RPRG) meeting, Powerlink, https://www.powerlink.com.au/2023-2027-regulatory-period.
8 Powerlink 2017-22 Final Decision, Attachment 2 – Regulatory Asset Base, Australian Energy Regulator, April 2017.
9 Powerlink Final Framework and Approach Paper 2022-27, Australian Energy Regulator, July 2020.

Table 10.2: Standard asset lives – as at 30 June 2022 (years)

Asset class	Standard life
Overhead lines	50
Underground lines	45
Lines (refit)	30
Substations primary plant	40
Substations secondary systems	15
Communications (civil works)	40
Communications – other assets	15
Network switching centres	12
Land	n/a(1)
Easements	n/a(1)
Commercial buildings	40
Computer equipment	5
Office furniture and miscellaneous	7
Office machines	7
Vehicles	7
Moveable plant	7
Insurance spares	n/a(1)

(1) Asset classes marked n/a do not depreciate.

10.6 Summary

Our depreciation forecast has been calculated consistent with regulatory and accounting requirements, using the AER's 2019 PTRM (Version 4), 2020 Roll Forward Model (RFM) (Version 4) and 2020 Depreciation Tracking Module (Version 1).

In its Final Decision on our 2023-27 Revenue Proposal, the AER will update our proposed forecast for final approved inputs.

We propose to change from the use of WARL to year-by-year depreciation tracking to forecast depreciation. We have proposed a minor extension to the WARL of the secondary systems asset class to reduce the impact of this change on consumers.

11. Maximum Allowed Revenue and Price Impact

11.1 Introduction

This chapter outlines Powerlink's Maximum Allowed Revenue (MAR) and forecast price impacts for the 2023-27 regulatory period.

Key highlights:

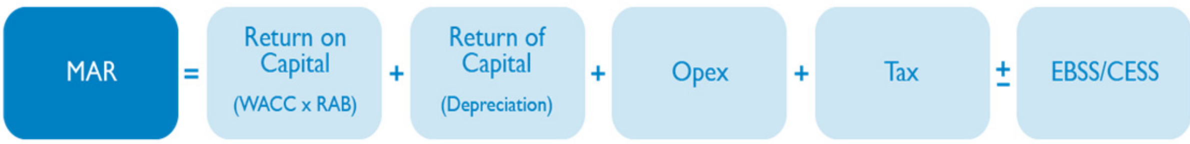
- Forecast MAR for the 2023-27 regulatory period is $3,333.9m. This is $587.4m (15%) lower than our allowed MAR for the 2018-22 regulatory period.
- The key driver of our reduced MAR is a lower forecast return on capital (refer Chapter 9 Rate of Return, Taxation and Inflation).
- The reduction in MAR results in a forecast reduction in the indicative transmission price in the first year of the next regulatory period of 11%. For average residential and small business customers, this represents an estimated saving in the first year of $13 and $23 respectively. This is on the basis of assumed tariffs and consumption[1].

11.2 Regulatory requirements

We have used the building-block approach outlined in the National Electricity Rules (the Rules)[2] to determine the MAR. The application of the building-block components produces the unsmoothed annual revenue requirement. This is demonstrated in Figure 11.1.

This revenue profile is then smoothed over the 2023-27 regulatory period based on an X-factor for the purpose of setting our final MAR and prices.

Figure 11.1: MAR building-block approach



Return on Capital = a measure of return on investments (capex)
Return of Capital = annual regulatory depreciation allowance
Opex = annual operating and maintenance cost allowance
Tax = calculated effective company tax payable
EBSS = carryover amounts for the Efficiency Benefit Sharing Scheme from the previous regulatory period
CESS = carryover amounts for the Capital Expenditure Sharing Scheme from the previous regulatory period

11.3 Forecast total revenue

Our total MAR for each year of the 2023-27 regulatory period is shown in Table 11.1. This is based on the application of each of the revenue building-blocks, which results in an unsmoothed revenue requirement for the 2023-27 regulatory period. The approach used to calculate each building-block element is explained in Section 11.5.

1 The transmission component of electricity bills is based on information from the Australian Energy Market Commission (AEMC) Electricity Price Trends Report, December 2020. Assumed residential consumption is based on the Queensland Competition Authority's (QCA's) annual Tariff 11 (residential) median energy usage of 4,061kWh p.a. Assumed small business consumption is based on the QCA's annual Tariff 20 (small business) median energy usage of 6,831kWh p.a

2 National Electricity Rules, clause 6A.5.4.

Table 11.1: Unsmoothed revenue requirement ($m nominal)

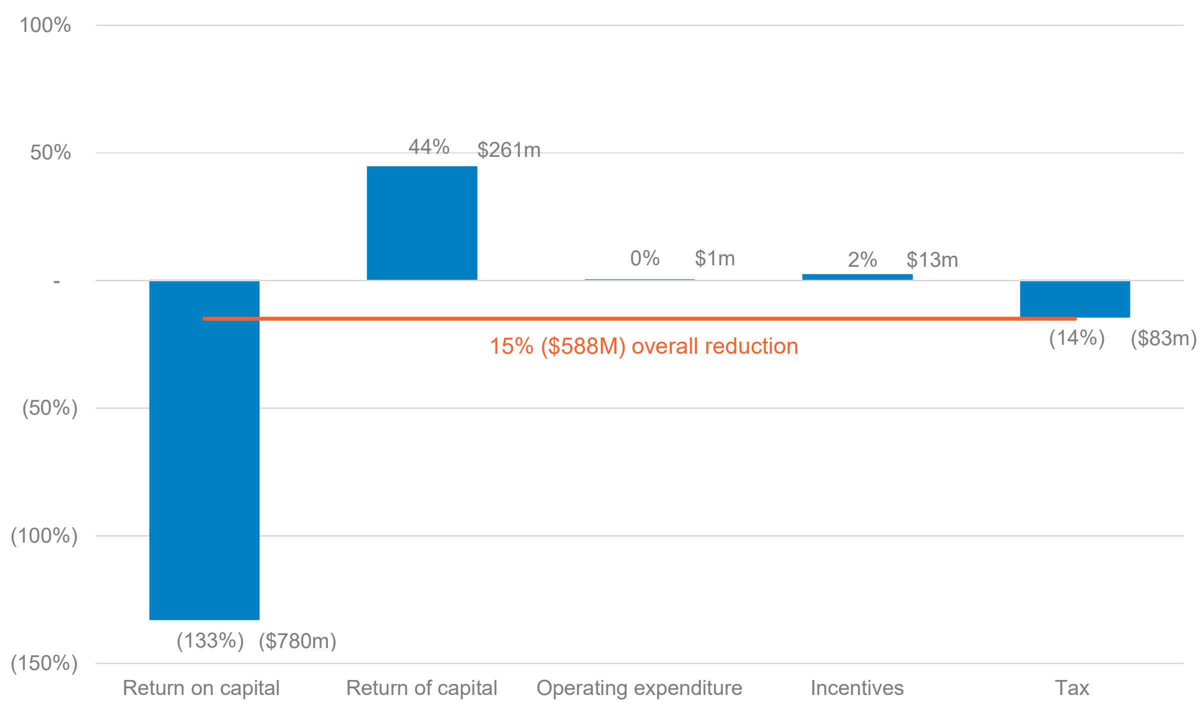
	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Return on capital	309.0	302.1	295.6	286.5	277.1	**1,470.3**
Return of capital	169.2	180.3	189.6	197.7	206.9	**943.7**
Operating expenditure	212.1	219.3	223.6	229.4	234.9	**1,119.3**
Taxation allowance	2.1	0.4	3.3	9.9	10.2	**25.9**
Efficiency Benefit Sharing Scheme (EBSS) carryover	8.5	(8.0)	-	1.8	6.8	**9.2**
Capital Expenditure Sharing Scheme (CESS) carryover	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	**(4.0)**
Unsmoothed revenue requirement	**700.2**	**693.4**	**711.3**	**724.5**	**735.0**	**3,564.4**

11.4 Change in MAR from the 2018-22 regulatory period

Our MAR is forecast to decrease by $587.4m (15%) compared to our allowed MAR for the 2018-22 regulatory period. Figure 11.2 shows the drivers of revenue change between the 2018-22 and 2023-27 regulatory periods. The key drivers are:

- *Return on capital:* $779.7m lower due to the lower rate of return (refer Chapter 9 Rate of Return, Taxation and Inflation).
- *Return of capital:* $261.2m higher due to the impact of a lower revaluation of the Regulatory Asset Base (RAB), the transitional impact from a change in our depreciation forecasting approach (refer Chapter 10 Depreciation) and an increase in depreciation from the recovery of prior years' indexation.
- *Incentives*: $13.1m higher due to a forecast revenue increment under the EBSS (refer Chapter 14 Expenditure Incentive Schemes).
- *Tax:* $83.3m lower, primarily due to the change in estimating taxation as a result of the Australian Energy Regulator's (AER's) 2018 Tax Review (refer Chapter 9 Rate of Return, Taxation and Inflation).

Figure 11.2: Drivers of revenue change



11.5 Our approach

We used the AER's 2019 Post-Tax Revenue Model (PTRM) (Version 4) to calculate the MAR. We have engaged with our customers on key changes to our approach that impact our MAR (refer Chapter 3 Customer Engagement).

The AER will update its revenue building-blocks for the relevant inputs and forecasts that underpin the MAR in its Final Decision.

11.5.1 Regulatory Asset Base

The value of our RAB determines our return on and return of capital allowances.

Our estimated opening RAB as at 1 July 2022 is $6,958.4m (nominal). Our approach to calculating this is outlined in Chapter 8 Regulatory Asset Base.

We have forecast a roll-forward of our RAB for each year of the 2023-27 regulatory period based on our forecasts for inflation (refer Chapter 9 Rate of Return, Taxation and Inflation), capital expenditure (refer Chapter 5 Forecast Capital Expenditure) and regulatory depreciation (refer Chapter 10 Depreciation). This is summarised in Table 11.2.

Table 11.2: Forecast RAB roll-forward 2023-27 regulatory period ($m nominal)

	2022/23	2023/24	2024/25	2025/26	2026/27
Opening RAB	6,958.4	6,985.4	7,025.2	7,004.2	6,973.4
Capital expenditure, as incurred(1)	196.2	220.1	168.6	166.9	172.4
Regulatory depreciation	(169.2)	(180.3)	(189.6)	(197.7)	(206.9)
Closing RAB	**6,985.4**	**7,025.2**	**7,004.2**	**6,973.4**	**6,939.0**

(1) Net of disposals, adjusted for inflation and one-half Weighted Average Cost of Capital (WACC) allowance[3]. The roll-forward also reflects capitalised movements in provisions.

11.5.2 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 9 Rate of Return, Taxation and Inflation.

Our return on capital forecast is presented in Table 11.3.

Table 11.3: Return on capital ($m nominal)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Opening RAB	6,958.4	6,985.4	7,025.2	7,004.2	6,973.4	N/A
Rate of return	4.44%	4.32%	4.21%	4.09%	3.97%	N/A
Return on capital	**309.0**	**302.1**	**295.6**	**286.5**	**277.1**	**1,470.3**

11.5.3 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 (refer Chapter 10 Depreciation).

3 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 in included in the RAB.

Our return of capital forecast is presented in Table 11.4.

Table 11.4: Return of capital ($m nominal)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Straight-line depreciation(1)	325.7	337.4	347.6	355.2	363.7	**1,729.5**
Indexation on opening RAB	(156.5)	(157.1)	(158.0)	(157.5)	(156.8)	**(785.8)**
Return of capital	**169.2**	**180.3**	**189.6**	**197.7**	**206.9**	**943.7**

(1) Straight-line depreciation is a method of calculating depreciation whereby an asset is expensed consistently throughout its useful life.

11.5.4 Operating expenditure

Our operating expenditure forecast (refer Chapter 6 Forecast Operating Expenditure) is shown in Table 11.5.

Table 11.5: Operating expenditure ($m nominal)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Controllable operating expenditure and insurances	202.4	209.5	213.6	219.2	224.6	1,069.4
Australian Energy Market Commission (AEMC) levy	6.0	6.2	6.4	6.5	6.7	31.8
Debt raising costs	3.6	3.6	3.6	3.6	3.6	18.1
Total operating expenditure	**212.1**	**219.3**	**223.6**	**229.4**	**234.9**	**1,119.3**

11.5.5 Taxation

Our forecast for taxation, applying a value for imputation credits of 0.585 consistent with the AER's 2018 Rate of Return Instrument (refer Chapter 9 Rate of Return, Taxation and Inflation), is presented in Table 11.6.

Table 11.6: Taxation ($m nominal)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Corporate tax	5.1	1.0	8.0	23.9	24.5	**62.5**
Value of imputation credits	(3.0)	(0.6)	(4.7)	(14.0)	(14.3)	**(36.6)**
Taxation	**2.1**	**0.4**	**3.3**	**9.9**	**10.2**	**25.9**

11.5.6 EBSS and CESS

Any efficiency gains or losses arising from the EBSS and CESS in the 2018-22 regulatory period are carried over as an adjustment to the MAR in the 2023-27 regulatory period (referred to as a carryover amount).

Our EBSS and CESS carryover amounts (refer Chapter 14 Expenditure Incentive Schemes) from the 2018-22 regulatory period are summarised in Table 11.7.

Table 11.7: EBSS and CESS carryover amounts ($m nominal)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
EBSS carryover	8.5	(8.0)	-	1.8	6.8	**9.2**
CESS carryover	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	**(4.0)**

11.6 X-factors and smoothed revenue

To reduce significant variations or smooth revenue in each year of our regulatory period, an X-factor is applied to our unsmoothed revenue requirement. As required by the Rules[4], the smoothed and unsmoothed revenue requirements are equivalent in net present value terms and the difference between the smoothed and unsmoothed revenue in the final year of the 2023-27 regulatory period is minimal at 0.2%. This smoothed revenue profile is the MAR that is used to set our prices each year. Our X-factors and smoothed MAR for the 2023-27 regulatory period are summarised in Table 11.8.

Table 11.8: X-factors and smoothed MAR ($m nominal)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Unsmoothed revenue requirement	700.2	693.4	711.3	724.5	735.0	**3,564.4**
X-factors	12.59%	0.57%	0.57%	0.57%	0.57%	
Smoothed MAR	**689.7**	**701.1**	**712.8**	**724.7**	**736.8**	**3,565.1**

In real terms, our smoothed revenue for 2022/23 is forecast to reduce by 12.59% compared to our forecast revenue in 2021/22. In subsequent years of the regulatory period our annual revenue is forecast to reduce by 0.57% per annum in real terms. Overall, our total MAR for the 2023-27 regulatory period is forecast to be 15% less than our allowed MAR for the 2018-22 regulatory period.

Within period our MAR will be updated each year to reflect:

- actual inflation;
- changes to the annual return on debt; and
- any approved cost pass throughs (refer Chapter 12 Pass Through Events).

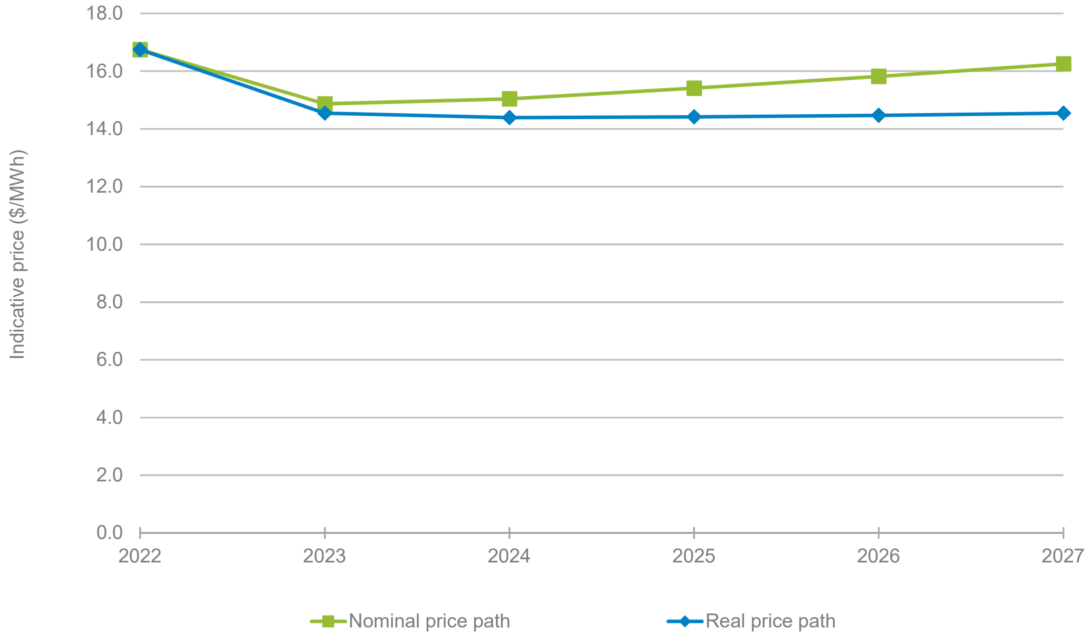
11.7 Average price path

We calculate our annual prescribed transmission charges consistent with our approved Pricing Methodology (refer Chapter 16 Pricing Methodology), which must comply with the requirements of the Rules and the AER's Pricing Methodology Guidelines for transmission networks[5].

To illustrate the indicative impact of our Revenue Proposal on average transmission prices under the regulatory framework, we divide our forecast MAR by forecast energy delivered in Queensland in each year of the 2023-27 regulatory period. This is shown in Figure 11.3.

[4] National Electricity Rules, clause 6A.6.8(c).
[5] Electricity Transmission Network Service Providers: Pricing Methodology Guidelines, Australian Energy Regulator, July 2014.

Figure 11.3: Indicative price path from 2021/22 to 2026/27



Powerlink's contribution to the average Queensland electricity bill is currently 9% for households and small businesses[6]. This equates to approximately $118.5 per annum for the average residential customer[7] and approximately $200.7 for the average small business[8].

Based on our forecast revenue, the indicative impact on the transmission component of electricity prices in the first year of the next regulatory period (2022/23) would be:

- *Residential*: a nominal reduction of $13 (11%), real reduction of approximately $16 (13%).
- *Small Business*: a nominal reduction of $23 (11%), real reduction of approximately $26 (13%).

On average, price increases for these customers will remain in line with inflation (assumed forecast of 2.25%) for the remainder of the 2023-27 regulatory period.

The estimated impact of our forecast revenue on the transmission component of average annual electricity bills in each year of the 2023-27 regulatory period is shown in Table 11.9. The final year of the current regulatory period is included to show the change relative to the first year of the next regulatory period.

Table 11.9: Estimated impact to transmission component of average annual electricity bills ($ nominal)

	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Residential annual bill(1)	118.5	105.2	106.4	109.0	111.9	115.0
Annual change	-	**(13.3)**	**1.2**	**2.6**	**2.9**	**3.1**
Small business annual bill(2)	200.7	178.2	180.3	184.7	189.6	194.8
Annual change	-	**(22.5)**	**2.1**	**4.4**	**4.9**	**5.2**

(1) Based on the QCA's annual Tariff 11 (residential) median energy usage of 4,061kWh per annum, March 2020.

(2) Based on the QCA's annual Tariff 20 (small business) median energy usage of 6,831kWh per annum, March 2020.

6 Residential Electricity Price Trends Report 2020, Australian Energy Market Commission, December 2020.
7 Based on the QCA's annual Tariff 11 (residential) median energy usage of 4,061kWh per annum, March 2020.
8 Based on the QCA's annual Tariff 20 (small business) median energy usage of 6,831kWh per annum, March 2020.

11.8 Summary

Powerlink's MAR for the 2023-27 regulatory period is forecast to decline by $587.4m (15%) compared to our allowed MAR for the 2018-22 regulatory period. This is primarily driven by a lower forecast rate of return.

Based on our forecast revenue, the indicative impact on the transmission component of electricity prices in the first year of the next regulatory period (2022/23) would be:

- *Residential*: a nominal reduction of $13 (11%), real reduction of approximately $16 (13%).
- *Small Business*: a nominal reduction of $23 (11%), real reduction of approximately $26 (13%).

We forecast average annual transmission prices over the 2023-27 regulatory period to remain in line with inflation.

12. Pass Through Events

12.1 Introduction

This chapter sets out the nominated and other pass through events proposed by Powerlink for the 2023-27 regulatory period.

The pass through event mechanism in the National Electricity Rules (the 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.
- Customers have advised they are concerned about rising insurance costs and the risk of cost pass throughs. We held a deep dive session on insurance in November 2020 to discuss the trade-offs between insurance costs and risk.
- We have committed to engage with customers within period in the event of any material changes in our insurance costs and prior to lodgement of any pass through applications to the Australian Energy Regulator (AER) should they be required.
- Having regard to the current insurance market, we have nominated the following pass through events for the 2023-27 regulatory period:
  - Insurance Coverage event;
  - Insurer Credit Risk event; and
  - Natural Disaster event.
- We have proposed a $0 network support allowance within our operating expenditure (refer Chapter 6 Forecast Operating Expenditure).
- We have flagged a number of potential areas in which we may need to seek a cost pass through within the next regulatory period.

12.2 Regulatory requirements

The Rules[1] 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;
5. any other event specified in a transmission determination as a pass through event for the determination;
6. an inertia shortfall event; and
7. a fault level shortfall event.

As identified above, the Rules allow a Transmission Network Service Provider (TNSP) to nominate pass through events as part of a Revenue Proposal. We have had regard to the considerations set out in Chapter 10 of the Rules[2] in the development of our nominated pass through events which are:

- whether the event is a pass through event for a transmission determination specified in clause 6A.7.3(a1)(1) to (4) of the Rules;
- whether the nature or type of event can be clearly identified at the time the determination is made for the service provider;
- whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event;

[1] National Electricity Rules, clause 6A.7.3(a1)
[2] National Electricity Rules, Chapter 10, definition of nominated pass through event considerations.

- whether the relevant service provider could insure against the event, having regard to:
  a. the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or
  b. whether the event can be self-insured on the basis that:
     i. it is possible to calculate the self-insurance premiums; 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
- any other matter the AER considers relevant and which the AER has notified Network Service Providers (NSPs) is a nominated pass through event consideration.

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 the Maximum Allowed Revenue (MAR) in the relevant year before a TNSP can seek a determination from the AER to pass through those costs[3]. For Powerlink, based on the MAR forecast in our Revenue Proposal, this threshold would be approximately $7.0m.

12.3 Nominated pass through events

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 mitigation 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 our 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.

We engaged Marsh to provide independent advice on our insurance and risk management approach for the 2023-27 regulatory period, including any risks that may need to be addressed as a nominated pass through event (refer to Appendix 12.01). Our proposed approach to insurance and self-insurance is addressed as part of our operating expenditure forecast (refer Chapter 6 Forecast Operating Expenditure).

Based on Marsh's advice, we propose the following nominated pass through events for the 2023-27 regulatory period:

- Insurance Coverage event;
- Insurer Credit Risk event; and
- Natural Disaster event.

We proposed and the AER approved the first two events, Insurance Coverage event and Insurer Credit Risk event, for application in our current regulatory period. We propose that Insurance Coverage events replace our previous term for this type of event (Insurance Cap event) to be consistent with the terminology applied by the AER in its recent regulatory decisions[4].

On the advice of Marsh, we have also proposed a new, Natural Disaster event. This was recommended given the increase in risk of natural catastrophe events and forecast increase in insurance premiums (refer Chapter 6 Forecast Operating Expenditure). In the current volatile and uncertain insurance market environment, insurance premiums for this class of insurance may become unsustainable over the 2023-27 regulatory period. If this occurs, it may be more prudent and efficient to reduce our premium coverage for some natural disaster events and rely on a Natural Disaster Event nominated pass through instead. 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 recent regulatory decisions[5].

The sections below set out our proposed definitions and justification for these events. We consider that our nominated pass through events are consistent with the requirements of the Rules[6].

3 National Electricity Rules, Chapter 10, definition of materially.
4 Draft Decisions for United Energy, AusNet Services, Jemena, CitiPower and Powercor, Australian Energy Regulator, September 2020.
5 *Ibid.*
6 National Electricity Rules, Chapter 10, definition of nominated pass through event considerations.

12.3.1 Insurance Coverage Event

An Insurance Coverage event is proposed to mitigate the risk of liability losses that exceed our insurance coverage. This event covers potential insurance gaps in relation to insurance caps as well as the possibility of withdrawn capacity or uneconomic increases in premiums in the future that could arise from the current and anticipated volatility in the insurance liability market.

Our proposed definition of an Insurance Coverage event is largely consistent with the AER's recent regulatory decisions[7] with some minor adjustments (underlined below) to capture where insurance coverage may comprise multiple layers and/or insurers.

Table 12.1: Proposed definition of an Insurance Coverage event

An Insurance Coverage Event occurs if:

1. Powerlink:
   (a) makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy (<u>in whole or in part</u>) or set of insurance policies; or
   (b) would have been able to make a claim or claims under a relevant insurance policy (<u>in whole or in part</u>) or set of insurance policies but for changed circumstances; and
2. Powerlink incurs costs:
   (a) <u>both within</u> and 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

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 <u>not</u> possible for Powerlink to take out an insurance policy (<u>in whole or in part</u>) 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:
  - o <u>the claimable component up to</u> the limit not been exhausted; or
  - o those costs not been unrecoverable due to changed circumstances.
- A relevant insurance policy (<u>in whole or in part</u>) 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 (<u>in whole or in part</u>) 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: In assessing an insurance coverage event through application under Clause 6A.7.3 of the Rules, the AER will have regard to:

1. The relevant insurance policy or set of insurance policies for the event;
2. 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
3. Any information provided by Powerlink to the AER about Powerlink's actions and processes.

[7] Draft Decisions for United Energy, AusNet Services, Jemena, CitiPower and Powercor, Australian Energy Regulator, September 2020.

Rationale

- An Insurance Coverage event is not covered by any of the categories of pass through events specified in clauses 6A.7.3(a1)(1) to (4) of the Rules.
- We consider that the nature and type of event can be clearly identified at the time the AER's determination is made.
- Events such as floods and cyclones could result in losses that exceed the limit of cover on existing insurances. The occurrence of an insurance coverage event is not foreseeable, has a low probability of occurrence but could potentially result in a high cost impact. We cannot prevent the occurrence of these type of events. While we invest, operate and maintain our network to reasonably 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 insurances beyond these limits of cover.
- We cannot control movements 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 on reasonable commercial terms. 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.

12.3.2 Insurer Credit Risk Event

An Insurance 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. Our proposed definition of an Insurer Credit Risk event is consistent with the AER's recent regulatory decisions[8].

Table 12.2: Proposed definition of an 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 provider.

Rationale

- An Insurer Credit Risk event is not covered by any of the categories of pass through events specified in clauses 6A.7.3(a1)(1) to (4) of the Rules.
- We consider that the nature and type of event can be clearly identified at the time the AER's determination is made.
- Given the prudent extent of insurance coverage we have in place, an insurer not being able to pay all, or part, of a large, or catastrophic, event could be financially significant for Powerlink.
- The risk of one of our insurers becoming insolvent is low but not improbable. While we act prudently in selecting an insurance provider, an insurer may still fail. Even though such events are infrequent, we are not able to control whether one or more of our insurers become insolvent.
- To mitigate against a potential Insurer Credit Risk event, we set minimum requirements for the credit rating of participating underwriters and monitor insurer ratings. Marsh provides regular updates on global insurer rankings, and recently provided access to a real time insurer monitor which captures insurer security ratings and movements.
- We diversify our risk through appropriate vertical and horizontal apportionment of our policies across both domestic and international providers. This combination also provides a level or risk mitigation against a potential Insurer Credit Risk event.

8 Draft Decisions for United Energy, AusNet Services, Jemena, CitiPower and Powercor, Australian Energy Regulator, September 2020

- 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.

12.3.3 Natural Disaster Event

A Natural Disaster 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. Our proposed definition of a Natural Disaster event is consistent with the AER's recent regulatory decisions[9].

Table 12.3: Proposed definition of a Natural Disaster event

Natural Disaster event means any natural disaster including but not limited to cyclone, fire, flood or earthquake that occurs during the 2023–27 regulatory control period that increases 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 the service provider 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 the service provider. 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.

Rationale

- A Natural Disaster event is not covered by any of the categories of pass through events specified in clauses 6A.7.3(a1) (1) to (4) of the Rules.
- We consider that the nature and type of event can be clearly identified at the time the AER's determination is made.
- 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, asset monitoring and maintenance activities along with existing insurance cover.
- We currently have insurance in place for towers and lines. However, Marsh have advised that this policy is subject to ongoing review and analysis:

  With the Towers & Lines insurance:

  - *there is a lack of general appetite with only a select group of insurers capable of underwriting this cover,*
  - *competition is minimal, and*
  - *there are limited alternative options outside current markets (unlike the ISR[10] policy, replacement capacity is not readily available).*

  Therefore, given the specialised nature of Towers & Lines insurance and the relatively small number of insurers willing to place such a policy, the continuity, terms and structure of this policy is subject to ongoing review and analysis[11].

- In the volatile and uncertain insurance market environment, insurance premiums for this class of insurance may become unsustainable over the 2023-27 regulatory period. Where insurance becomes unavailable on reasonable commercial terms, it may be more prudent and efficient to reduce or remove the level of insurance coverage. A natural disaster pass through is likely to be the most appropriate way to manage this risk, and is more likely to be in the long-term interests of consumers when considering the trade-off between rising insurance premiums and the likelihood of an event occurring.
- We consider that the treatment of natural disasters as a nominated pass through event represents a more efficient means of managing our risk exposure than self-insurance given the complexity associated with developing credible self-insured risk quantifications for very low probability events and our likely inability to cover the cost impacts of a major natural disaster through a self-insurance allowance.

9 Draft Decisions for United Energy, AusNet Services, Jemena, CitiPower and Powercor, Australian Energy Regulator, September 2020.
10 Industrial Special Risks.
11 Nominated Pass Through Events Powerlink Queensland, Marsh, December 2020, page 9.

12.4 COVID-19

The COVID-19 pandemic has created significant uncertainty and has impacted both domestic and global economies. Marsh has highlighted the unprecedented impact this is having on the global insurance market. At the time of writing our Revenue Proposal, the full extent that COVID-19 claims will have on coverage and pricing of some classes of insurance is still uncertain. This may also impact insurers in terms of maintaining solvency and acceptable financial ratings. We will continue to monitor and actively manage any upward pressure on premiums and ongoing insurance coverage.

While stand-alone pandemic products are available, they are limited and the availability of coverage and limits is insignificant considering the cost. Marsh advise there is little appetite for clients to pursue this option. For certain classes of insurance, the insurance market is introducing communicable disease exclusions that will effectively eliminate coverage over time. Our insurance policies have limited coverage for pandemics and this is expected to continue to reduce with more exclusions from insurers.

From a regulatory perspective, the framework provides some flexibility to enable a TNSP to seek to recover additional costs in such circumstances where these are material. For example, pass through provisions in relation to a regulatory change event or service standard event. The Rules also allow anyone, including industry participants, to request a change to the Rules. Subject to relevant Rules provisions and the Australian Energy Market Commission's (AEMC's) assessment, such a request can be sought as urgent and progressed on an expedited basis.

As many stakeholders will be aware, the AER itself took proactive action in relation to COVID-19 and sought input and feedback from networks and consumer groups on a potential re-opener Rule change to address the consequential cost impacts. As it turns outs, based on this feedback, the AER decided not to proceed with the Rule change request.

12.5 Network support pass through

We have identified the potential for future network support arrangements with generators and large loads to form part of an upgraded scheme to extend the power transfer limits between Central Queensland and Southern Queensland. However, at this time, development of the need and full justification has yet to be undertaken. These costs, if they provide a net market benefit, form an efficient use of operating expenditure in place of capital expenditure.

Under the Rules[12], a TNSP can seek a determination from the AER to pass through any differences in costs between the amount included in the annual revenue requirement and actual efficient costs associated with network support events.

Given the uncertainty around the costs associated with the potential need identified above and other needs that could arise during the next regulatory period, we have proposed a $0 network support allowance for the 2023-27 regulatory period. If network support is required and can be justified within period, we will seek a network support pass through from the AER at that time (refer Chapter 6 Forecast Operating Expenditure).

12.6 Potential pass through events in the 2023-27 regulatory period

Pass through events are typically uncontrollable, material and uncertain (as to if, or when, they will occur and/or their total cost).

Customers have advised they are concerned about increases in insurance premiums and the risk of cost pass throughs. We held a deep dive session on insurance in November 2020 and discussed the trade-off between certainty of insurance costs and the uncertainty of pass through risk.

In light of customer concerns and volatility in the insurance market, we have committed to engage with customers in the event of any material changes in our insurance costs within period and prior to lodgement of any pass through applications to the AER should they be required.

As many stakeholders are aware, at any one time there are numerous external consultations associated with Rule changes and reviews underway that may have cost consequences for networks and ultimately, consumers. Typically, stakeholders such as the AEMC, AER and networks will seek to address obligations and cost recovery in the context of each consultation, which may include cost pass through arrangements.

To be open and transparent, we have identified several potential pass through events that may eventuate in the next regulatory period that relate to the provision of prescribed transmission services. While not an exhaustive list, these events or drivers are shown in Table 12.4.

[12] National Electricity Rules, clause 6A.7.2.

If these or any other events occur during the 2023-27 regulatory period we will assess the most efficient way to manage these costs, which may result in a cost pass through application to the AER. Whether these events will occur or would qualify as a pass through event under the Rules is not known at this time.

Table 12.4: Potential cost pass through events in 2023-27 regulatory period

Pass through event	Description
Cyber security	In December 2020, the Federal Government introduced the *Security Legislation Amendment (Critical Infrastructure) Bill 2020* to Parliament. If passed, this legislation would establish a new security and resilience regulatory regime on operators of critical infrastructure and we anticipate there would be elevated security obligations and standards on critical infrastructure owners and operators such as Powerlink. We considered an operating expenditure step change for a potential uplift in costs related to this requirement. We have decided not to pursue this and to aim to absorb these costs within our proposed operating expenditure forecast (refer Chapter 6 Forecast Operating Expenditure). However, if these costs are material, we may need to consider a cost pass through arrangement within period.
Transmission Ring-Fencing	The AER's Electricity Transmission Ring-Fencing Guideline Review[1] may result in additional costs for Powerlink. The quantum of these costs will depend on the nature and extent of the changes proposed and will need to be assessed after publication of the AER's Draft Guideline, indicatively scheduled for release in September 2021.
Inertia shortfall and fault level shortfall events	The change in generation mix presents particular challenges for the network (refer Chapter 2 Business and Operating Environment). In its 2020 System Strength and Inertia Report, the Australian Energy Market Operator (AEMO) concluded that fault level and inertia shortfalls are not yet considered likely for Queensland in the next five years, but shortfall risks are increasing. Changes to the operating patterns of large synchronous generators could result in either or both types of shortfall being declared during the 2023-27 regulatory period. AEMO declared a fault level shortfall event in North Queensland in April 2020 and we are required to meet this shortfall by August 2021. We have sought potential non-network solutions and have started to implement arrangements to meet this need. An application to the AER to approve the pass through of these network support costs will be made after the end of 2020/21.

(1) Electricity Transmission Ring-Fencing Guideline Review Discussion Paper, Australian Energy Regulator, November 2019.

12.7 Summary

We have nominated three cost pass through events for inclusion in our transmission determination, consistent with the Rules.

We have also proposed a $0 network support allowance and will manage any network support costs which may arise during the 2023-27 regulatory period by seeking a network support pass through from the AER if required.

13. Shared Assets

13.1 Introduction

Shared assets are assets used to provide both prescribed and either non-regulated transmission services or services that are not transmission services[1]. 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 2023-27 regulatory period. The purpose of this assessment is to determine whether any adjustment is required to our proposed annual revenue.

Key highlights:

- Shared Asset Unregulated Revenues (SAUR) for the 2023-27 regulatory period have been assessed as not material, based on the Australian Energy Regulator's (AER's) 2013 Shared Asset Guideline (the 2013 SA Guideline) approach. Therefore, we have not adjusted our proposed annual revenues in our Revenue Proposal.

13.2 Regulatory requirements

The National Electricity Rules (the Rules)[2] allow the 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 2013 SA Guideline[3].

The 2013 SA Guideline sets out the following process to establish the shared asset cost reduction for each year of the regulatory period:

- determine the SAUR;
- determine whether the SAUR is material (i.e. exceeds 1% of the proposed annual revenue requirement); and
- 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 2023-27 regulatory period.

The 2013 SA Guideline 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 2013 SA Guideline approach.

In addition, the 2013 SA Guideline states that where assets provide prescribed transmission services and unregulated services consistent with a TNSP's Cost Allocation Methodology, the shared asset mechanism does not apply.

13.3 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 2023-27 regulatory period. As a result, we propose no adjustment to our annual revenues in our Revenue Proposal (see Table 13.1).

1 National Electricity Rules, clause 6A.5.5(a).
2 National Electricity Rules, clause 6A.5.5.
3 Shared Asset Guideline, Australian Energy Regulator, November 2013.

Table 13.1: Materiality assessment ($m nominal)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Proposed smoothed Maximum Allowed Revenue (MAR)	689.7	701.1	712.8	724.7	736.8	**3,565.1**
1% of smoothed MAR	6.9	7.0	7.1	7.2	7.4	**35.6**
Average annual SAUR	3.2	3.2	3.2	3.2	3.2	**15.8**
SAUR as % MAR	0.5%	0.5%	0.4%	0.4%	0.4%	
Exceed 1% Materiality Test	**No**	**No**	**No**	**No**	**No**	

13.4 Our approach

We have applied the AER's approach outlined in Section 13.2 to determine whether a revenue adjustment should be applied. We have adopted the same methodology to estimate our SAUR as applied in our previous Revenue Proposal.

13.4.1 Shared asset unregulated revenues

We have identified three categories of non-regulated services that use shared assets and are applicable to the shared assets mechanism in the 2023-27 regulatory period. These are:

- Oil testing and laboratory services – specialist oil testing, Sulphur Hexafluoride (SF_6) gas testing and diagnostic services from our on-site laboratory.
- Property rentals – rental income may be generated from property (land or buildings) acquired by Powerlink either directly or incidentally to the purchase of property required for the future development of our prescribed transmission network.
- Tower access – where space on transmission and communications towers is provided to co-locate mobile phone carriers' equipment.

Table 13.2 set outs Powerlink's forecast of unregulated revenues for these services provided by means of shared assets.

Table 13.2: Forecast SAUR ($m real, 2021/22)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Oil testing and laboratory services	0.3	0.3	0.3	0.3	0.3	**1.3**
Property rentals	0.6	0.4	0.4	0.7	0.7	**2.8**
Tower access	2.2	2.2	2.2	2.2	2.2	**10.9**
Total	**3.1**	**2.9**	**2.9**	**3.1**	**3.1**	**15.0**

13.4.2 Materiality

The 2013 SA Guideline states 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 for the three categories of non-regulated services applicable to the shared assets mechanism in the 2023-27 regulatory period are not forecast to exceed the 1% materiality threshold in any year. As a result, no revenue adjustment has been applied.

13.5 Summary

We have assessed that forecast shared asset unregulated revenues for the 2023-27 regulatory period are not material. Therefore, no revenue adjustment has been applied in our Revenue Proposal.

14. Expenditure Incentive Schemes

14.1 Introduction

This chapter outlines net carryover amounts from the current 2018-22 regulatory period and Powerlink's targets for the Efficiency Benefit Sharing Scheme (EBSS) and the Capital Expenditure Sharing Scheme (CESS) for the 2023-27 regulatory period. The EBSS relates to operating expenditure and the CESS relates to capital expenditure.

Key highlights:

- For the EBSS, we:
  - estimate a net positive carryover amount of $8.4m from the 2018-22 regulatory period be used to adjust the Maximum Allowed Revenue (MAR) for the 2023-27 regulatory period; and
  - propose that $999.7m of our forecast operating expenditure for the 2023-27 regulatory period be subject to the EBSS.
- For the CESS, we:
  - estimate a net negative carryover amount of -$3.7m from the 2018-22 regulatory period be used to adjust the MAR for the 2023-27 regulatory period; and
  - propose that $858.9m of our forecast capital expenditure for the 2023-27 regulatory period be subject to the CESS.

14.2 Regulatory requirements

In its Final Framework and Approach Paper[1] for Powerlink, the Australian Energy Regulator (AER) proposes to apply its 2013 EBSS (Version 2) and 2013 CESS (Version 1) to our 2023-27 regulatory period. Our Revenue Proposal aligns with that approach.

14.3 Efficiency Benefit Sharing Scheme

The purpose of the EBSS is to provide a continuous incentive for Network Service Providers (NSPs) to pursue efficiency improvements in operating expenditure. The EBSS also enables efficiency gains (or losses) to be shared between a NSP and its network users.

14.3.1 Carryover amount from the 2018-22 regulatory period

Under the EBSS, our MAR for the 2023-27 regulatory period is adjusted for a portion of operating expenditure efficiency gains/losses accrued during the 2018-22 regulatory period (the carryover amount)[2]. Our total EBSS carryover amount from the 2018-22 regulatory period is $8.4m as shown in Table 14.1.

Table 14.1: EBSS carryover amount ($m real, 2021/22)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
EBSS carryover	8.3	(7.6)	-	1.6	6.1	**8.4**

Our calculated EBSS carryover is based on the difference between our actual/forecast operating expenditure target (for the purpose of the EBSS) for the first three years of the 2018-22 regulatory period and an estimate of that difference for the last two years (2020/21 and 2021/22)[3]. We have also adjusted our forecast and actual operating expenditure in each year of the 2018-22 regulatory period for inflation.

Adjustments

We excluded $12.1m (nominal) of non-recurrent expenditure related to 500kV project costs from the 2014/15 base year operating expenditure to forecast operating expenditure for the 2018-22 regulatory period to establish an efficient level of recurrent expenditure. Consistent with this treatment, we have made an adjustment in the EBSS model to recognise the non-recurrent efficiency adjustment made to 2014/15 to calculate the incremental efficiency gain for 2017/18.

1 Final Framework and Approach for Powerlink, Australian Energy Regulator, July 2020.
2 Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, Australian Energy Regulator, November 2013, Section 1.3.
3 The AER will adjust for 2020/21 actuals in its Final Decision.

An adjustment of $0.4m was made to remove expenditure associated with a Network Capability Incentive Parameter Action Plan (NCIPAP) project that was undertaken in 2017/18 and 2018/19 (refer Chapter 15 Service Target Performance Incentive Scheme). This is consistent with the AER's Service Target Performance Incentive Scheme (STPIS)[4], as NCIPAP projects do not form part of our operating expenditure forecasts.

Movements in provisions related to operating expenditure of $1.9m have also been excluded in the EBSS model. This is consistent with the AER's treatment of these costs in the 2018-22 regulatory period and the AER's 2013 Expenditure Forecast Assessment Guideline[5].

These adjustments were discussed and confirmed with AER staff prior to the lodgement of our Revenue Proposal.

14.3.2 EBSS target for the 2023-27 regulatory period

Our total EBSS target for the 2023-27 regulatory period is $999.7m and is shown in Table 14.2.

Table 14.2: EBSS target ($m real, 2021/22)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Operating expenditure forecast	207.4	209.8	209.2	209.9	210.1	**1,046.4**
Adjustments						
Debt raising costs	3.5	3.5	3.4	3.3	3.2	**17.0**
Network support costs	-	-	-	-	-	**-**
Australian Energy Market Commission (AEMC) Levy	5.9	5.9	5.9	6.0	6.0	**29.7**
EBSS target	198.0	200.4	199.8	200.6	200.9	**999.7**

We have used 2018/19 as our base year to forecast our operating expenditure for the 2023-27 regulatory period (refer Chapter 6 Forecast Operating Expenditure).

Consistent with Version 2 of the EBSS[6], we have excluded categories of operating expenditure not forecast using a single year revealed cost approach for our proposed EBSS target for the 2023-27 regulatory period. This includes debt raising, network support and the AEMC Levy cost categories.

These adjustments have been discussed with AER staff prior to the lodgement of our Revenue Proposal.

14.4 Capital Expenditure Sharing Scheme

The purpose of the CESS is to provide a continuous incentive for NSPs to undertake efficient capital investments. As with the EBSS, the CESS enables efficiency gains (or losses) to be shared between the NSP and network users.

14.4.1 Carryover amount from the 2018-22 regulatory period

The CESS requires that we adjust our MAR for the 2023-27 regulatory period for our share of any capital expenditure efficiency gains/losses from the 2018-22 regulatory period (the carryover amount).

Our total CESS carryover amount from the 2018-22 regulatory period is negative $3.7m as shown in Table 14.3.

Table 14.3: CESS carryover amount ($m real, 2021/22)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
CESS carryover	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	**(3.7)**

This calculation is based on the difference between our actual/forecast capital expenditure target (for the purpose of the CESS) for the first three years of the 2018-22 regulatory period and a forecast of that difference for the last two years (2020/21 and 2021/22)[7]. We have also adjusted our forecast and actual capital expenditure in each year of the 2018-22 regulatory period for inflation.

[4] Service Target Performance Incentive Scheme, Australian Energy Regulator, October 2015, clause 5.2 (r)(1).
[5] Expenditure Forecast Assessment Guideline for Electricity Transmission, Australian Energy Regulator, November 2013, page 22.
[6] Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, Australian Energy Regulator, November 2013, Section 1.4.
[7] As with the EBSS, the AER will adjust for 2020/21 actuals in its Final Decision.

Adjustments

Our capital expenditure forecast for 2018-22 included a proposed office building refit project. This has been deferred to the 2023-27 regulatory period as outlined in Chapter 4 Historical Capital and Operating Expenditure. We intend to return the revenue attributable to the capital expenditure allowance for this project to customers in 2021/22. We also propose to adjust for this deferred capital expenditure in the calculation of the CESS carryover to remove the CESS payment for the capital expenditure underspend in the current regulatory period associated with this project.

Movements in provisions related to capital expenditure have also been excluded in the CESS model. This is consistent with the AER's 2013 Capital Expenditure Incentive Guideline[8].

14.4.2 CESS target for the 2023-27 regulatory period

Our total CESS target for the 2023-27 regulatory period is $858.9m and is shown in Table 14.4.

Table 14.4: CESS target ($m real, 2021/22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Capital expenditure forecast	190.9	209.4	157.2	152.4	154.0	**863.9**
Adjustments	-	-	-	-	-	**-**
Movement in provisions	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	**(5.0)**
CESS target	189.9	208.4	156.2	151.4	153.0	**858.9**

Consistent with 2013 CESS (Version 1), adjustments may be made during the 2023-27 regulatory period for any capital expenditure approved by the AER for contingent projects that are triggered. Our proposed contingent projects are outlined in our capital expenditure forecast (refer Chapter 5 Forecast Capital Expenditure).

14.5 Summary

We have proposed carryover amounts and targets for the EBSS and CESS consistent with the AER's incentive guidelines and its Final Framework and Approach Paper for Powerlink for the 2023-27 regulatory period.

8 Capital Expenditure Incentive Guideline for Electricity Network Service Providers, Australian Energy Regulator, November 2013.

15. Service Target Performance Incentive Scheme

15.1 Introduction

This chapter outlines Powerlink's performance under the Service Target Performance Incentive Scheme (STPIS) in the current 2018-22 regulatory period, as well as our proposed STPIS values and targets for the 2023-27 regulatory period.

The three components to the STPIS are the Service Component (SC), Market Impact Component (MIC) and Network Capability Component (NCC).

Key highlights:

- Our STPIS performance for the SC and NCC for the current 2018-22 regulatory period demonstrates improved network performance.
- Changes in power flows and the emergence of system strength constraints have impacted our MIC performance. This is expected to continue into the 2023-27 regulatory period.
- We propose an alternative target of one in lieu of zero for the large loss of supply event sub-parameter of the SC.
- We do not propose any Network Capability Incentive Parameter Action Plan (NCIPAP) projects in our Revenue Proposal. We will consider potential NCIPAP projects further and may propose projects to the Australian Energy Regulator (AER) within the 2023-27 regulatory period.
- We have proposed SC and MIC targets consistent with the AER's historical data ranges[1] and our alternative proposed data range, which incorporates the most recent calendar year. This is to ensure our 2023-27 target incorporates the impact of significant changes in our operating environment.
- We engaged WSP to independently assess the robustness of our methodology to determine the best fit statistical distributions for the SC. WSP concluded our approach is robust.

15.2 Regulatory requirements

The National Electricity Rules (the Rules)[2] require the AER to develop and publish a STPIS that complies with specified principles. We are required to include proposed values for the STPIS parameters as part of our Revenue Proposal[3].

We are currently subject to the AER's 2015 STPIS (Version 5) and our Revenue Proposal complies with Version 5. In its Final Framework and Approach paper for Powerlink[4], the AER confirmed that it will apply this version of the scheme for the 2023-27 regulatory period.

15.3 STPIS in the current environment

There have been some significant changes in our operating environment as Australia's energy market transitions to a low carbon future (refer Chapter 2 Business and Operating Environment). These changes, which have occurred since the AER's 2015 STPIS was published, have presented a number of challenges in the management of our network performance. Given the intent and scope of the STPIS, the changes of particular importance here are:

- ***Changes in power flows***: with over 1,000MW of new wind and solar generation connected to our transmission network in Central and North Queensland since 2017, there has been a significant increase in north-south intra-regional power flows along our transmission network. This has created a situation where system normal constraints are binding more often, which can severely restrict outage windows despite efforts to plan outside these periods.
- ***The emergence of system strength constraints***: system strength is a characteristic of an electrical power system that relates to the size of the change in voltage following a fault or disturbance on the power system[5]. It has emerged as a prominent challenge in Queensland (particularly in North Queensland) as well as other parts of the National Electricity Market (NEM), which is discussed further below.

1 Reset Regulatory Information Notice (RIN): clauses 11.1 and 11.2, Australian Energy Regulator, October 2020.
2 National Electricity Rules, clause 6A.7.4.
3 National Electricity Rules, schedule 6A.1, clause S6A.1.3(2).
4 Final Framework and Approach: Powerlink, Australian Energy Regulator, July 2020.
5 Managing Power System Fault Levels Rule Determination, Australian Energy Market Commission, September 2017, page 3.

In May 2019, the Australian Energy Market Operator's (AEMO's) National Electricity Market Dispatch Engine (NEMDE) was updated to recognise system strength constraints in Queensland. AEMO formally declared a fault level shortfall in North Queensland in April 2020[6]. The fault level shortfall occurred due to the significant number of Inverter-Based Resources (IBR) that connected to the North Queensland transmission network. These constraints only became apparent in Queensland in 2019 and are therefore not reflected in the historical constraint data before 2019.

The main driver of the increase in constraints is the rapid change in the mix and location of generation, which is not directly within our control. North Queensland now has the third highest proportion of solar and wind generation in the world, only slightly behind Denmark and South Australia[7]. With limited base load synchronous generation in North Queensland and large distances between the synchronous generators in Central and Southern Queensland, this creates low system strength conditions in North Queensland.

We continue to respond to these challenges to ensure that the needs of our customers are met and that we continue to meet our network security and reliability obligations. This involves alignment of activities and executing work in a way that has the least practicable impact to customers, such as working coincident with customer outages, live work on transmission lines and substations, consolidation of outages and the use of shoulder periods.

These changes have impacted our MIC performance in the 2018-22 regulatory period and will influence our MIC targets for the 2023-27 regulatory period. This is discussed further in Section 15.5 and Appendix 15.01 Setting STPIS Values.

15.3.1 Review of STPIS

In October 2019, we raised concerns with the AER about whether the STPIS is still fit-for-purpose as part of our Framework and Approach (F&A) initiation, in light of the rapid changes that have occurred within the energy market post-2015[8].

Following further discussion, the AER responded to us in November 2019 to advise it did not consider a STPIS review appropriate at the present time. We provided further information in January 2020 to support a review, which also had support from our Revenue Proposal Reference Group (RPRG)[9]. Other Transmission Network Service Providers (TNSPs), via Energy Networks Australia (ENA), called for a review of the STPIS in February 2020 (refer to Appendix 15.02) and noted this issue was particularly pressing for Powerlink, given the timing of our revenue determination process. In May 2020, at the request of the AER we provided further evidence to support a review.

In the AER's July 2020 Final F&A Paper, the AER concluded that the STPIS is operating appropriately[10]. We received a formal response from the AER in August 2020 that there was no immediate need for a review. The AER advised that a review will be required in the future to respond to NEM changes resulting from the expected implementation of the Coordination of Generation and Transmission Investment (COGATI) reforms, the Australian Energy Market Commission's (AEMC's) investigation into system strength frameworks in the NEM and the Energy Security Board's (ESB's) Post-2025 Market Design Review.

We remain firmly of the view that the 2015 STPIS should be reviewed as a matter of urgency, and that the current arrangements to apply to Powerlink for the 2023-27 regulatory period are not fit-for-purpose. More broadly, the current arrangements do not appear to promote the long-term interests of customers and are inconsistent with the principles upon which the incentive schemes have been established by the AER under the Rules – to provide genuine financial incentives for improvements in market performance.

Our view is that all elements of the regulatory framework, and regulatory bodies, should adapt to significant changes in the energy market and operating environment.

15.4 Historical performance in the 2018-22 regulatory period

Our performance for the SC, MIC and NCC components of the scheme over the current 2018-22 regulatory period are summarised in Table 15.1. Overall, our STPIS performance demonstrates continued improvement, with the exception of MIC performance due to the reasons outlined in Section 15.3.

6 Notice of Queensland System Strength Requirements and Ross Fault Level Shortfall: A Report for the National Electricity Market, Australian Energy Market Operator, April 2020.
7 World Energy Outlook 2018, IEA, 2018.
8 Framework and Approach initiation, Powerlink, October 2019.
9 Meeting Minutes of January 2020 RPRG, Powerlink, https://www.powerlink.com.au/2023-2027-regulatory-period.
10 Framework and Approach: Powerlink, Australian Energy Regulator, July 2020, page 12.

STPIS operates and data is reported to the AER on a calendar year basis. As our current regulatory period commenced on 1 July 2017, the information below reflects performance for the second half of that year. The AER's 2015 STPIS requires that a two-year rolling average is used to report the SC performance of the unplanned outage circuit event rate and average outage duration.

Table 15.1: Historical STPIS annual compliance performance 2017 2H to 2020

Parameter	Unit of Measure	2018-22 Target	Calendar year			
			2017 2H	2018	2019	2020
Service Component						
Unplanned outage circuit event rate(1)						
Lines event Rate – Fault	Rate	20.88	17.43	21.61	20.62	12.86
Transformer event rate – Fault	Rate	18.91	17.21	22.81	19.01	12.54
Reactive plant event rate – Fault	Rate	29.85	26.84	27.67	26.02	23.59
Lines event rate – Forced	Rate	20.39	17.26	17.24	16.24	18.39
Transformer event rate – Forced	Rate	19.17	16.62	14.62	11.11	15.15
Reactive plant event rate – Forced	Rate	24.23	22.06	21.40	20.82	20.97
Loss of supply events frequency						
Loss of supply events > 0.05 (x) system minutes	Count	3	2	2	0	0
Loss of supply events > 0.40 (y) system minutes	Count	1	0	1	0	0
Average outage duration(1)						
Average outage duration	Minutes	94	29	32	26	36
Proper operation of equipment(2)						
Failure of protection system	Number	N/A	21	38	15	21
Material failure of Supervisory Control and Data Acquisition (SCADA) system	Number	N/A	0	2	0	0
Incorrect operational isolation of primary or secondary equipment	Number	N/A	2	2	5	9
Market Impact Component						
MIC	Number of Dispatch Intervals (DI)	333	9	217	13,152(3)	23,909(4)
Network Capability Component						
NCIPAP	The priority project 'Increase design temperature of two 275kV transmission lines' was completed and achieved its target limit value.					

(1) Two-year rolling average performance is reported as required by the AER's 2015 STPIS.

(2) Report only parameter with no weighting.

(3) In March 2020, the AER advised us that AEMO made manual changes to its Marginal Constraint Cost (MCC) data after we lodged our annual STPIS report for the 2019 regulatory period to the AER. We re-ran the data and identified that the updated dataset would have added on an extra 532 DIs to our original 2019 result of 12,620 DIs. AEMO's additional DIs have been included in the calendar year figure in the table.

(4) The calendar year 2020 MIC performance result that Powerlink reports in the 2023-27 Reset RIN Return (7.9 STPIS Alternative) and in our annual 2021 STPIS submission is our estimate based on the MCC data which was made available by AEMO on 15 January 2021. We will update the AER on any changes to the 2020 MCC as part of the AER's review of our Revenue Proposal prior to its September 2020 Draft Decision. We will also update data in our Revised Revenue Proposal to be submitted in December 2021.

The following sections outline our historical performance for each parameter in the current regulatory period, which informs our caps, floors and targets for the 2023-27 regulatory period. The targets outlined in Table 15.3 have been calculated using the year ranges indicated in Figures 15.1 to 15.10. We have also provided 2020 calendar year data for information.

15.4.1 Service Component performance

Our overall performance under the SC consistently exceeded the AER's target in this regulatory period. Positive performance under the SC minimises the impact of unplanned outages and loss of supply on customers. We have responded to the AER's 2015 STPIS and have modified our approach to non-urgent plant issues which in the past would have resulted in forced outages with less than 24 hours notice to our customers. Where possible, we have delayed our response to non-urgent plant issues, for example low gas alarms from circuit breakers, and as a result, provide more time for our customers to better plan and prepare their operations prior to an outage. From a broader perspective, in the current regulatory period, we have on average experienced fewer climatic related impacts to our network.

The combination of our ongoing asset management practices and fewer climatic events has resulted in us performing well against the large (y) loss of supply events frequency sub-parameter. Only one loss of supply event exceeded the threshold of 0.40 system minutes in the past five years, which has resulted in near-ceiling performance for this measure. The implications of this for our target for the 2023-27 regulatory period are discussed in Section 15.5.4.

We detail our performance against the three SC parameters – unplanned outage circuit event rate, loss of supply events frequency and average outage duration – in the following sections.

Service Component performance – unplanned circuit outage event rate

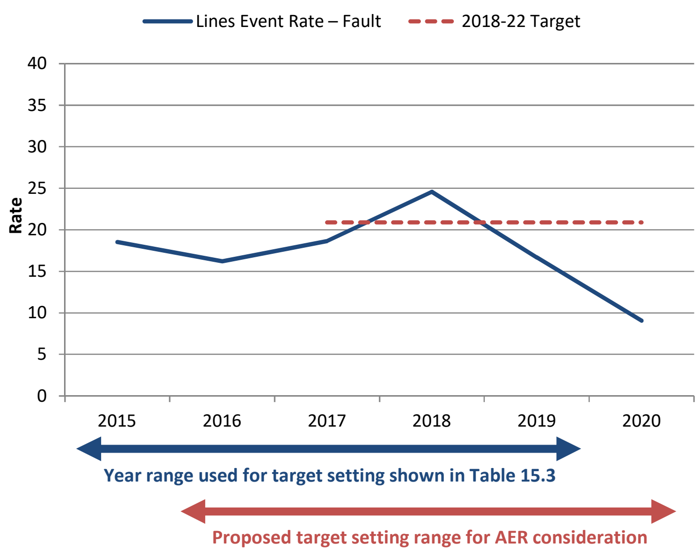
Unplanned outage circuit event rate – Fault

A fault outage is any element outage that occurred as a result of an element being switched off (such as a transformer) 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 transmission element 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 of our assets.

The historical performance of our fault outage circuit rates since 2015 for transmission lines, transformers and reactive plant is shown in Figures 15.1, 15.2 and 15.3.

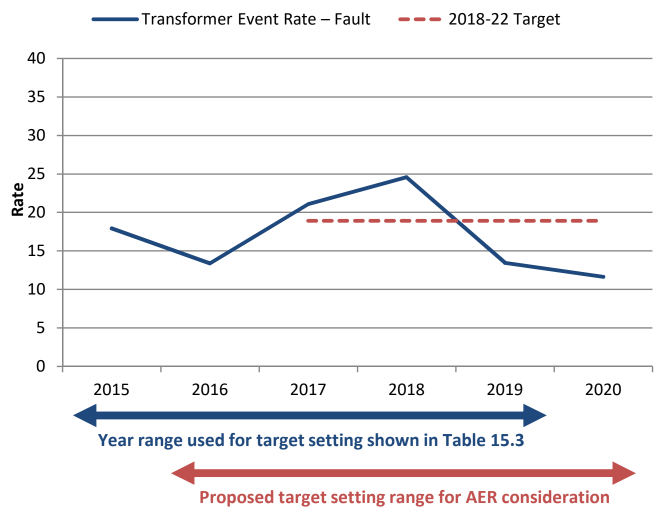
Figure 15.1: Lines event rate – Fault 2015-2020



The lines fault event rate sub-parameter performed better than the target, except for 2018 when a higher than average number of busbar trips impacted transmission lines. These occurred, for example, due to lightning and abnormal age-related deterioration and a loose wiring connection.

In 2019 and 2020, less than the average number of weather events impacted the network. As a result, the lines fault event rate decreased and returned to a performance level better than the target.

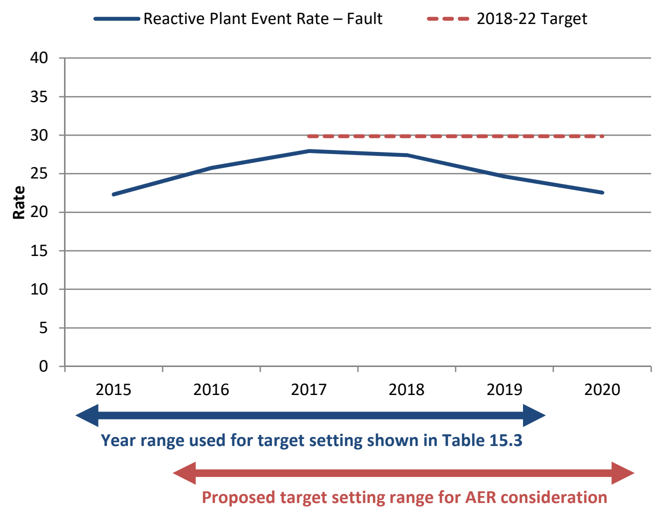
Figure 15.2: Transformer event rate – Fault 2015-2020



The transformer fault event rate did not meet the target in 2017[11] and 2018. This was due to a higher than average number of transformer circuit breaker issues and a higher than average number of faults on transformer ended feeders. These occurred, for example, due to water ingress into circuitry, lightning faults and pollution build-up on line insulators.

In 2019 and 2020, the sub-parameter performed better than the target due to a return to normal of the number of connection equipment related issues.

Figure 15.3: Reactive plant event rate – Fault 2015-2020



The reactive plant fault event rate sub-parameter performed consistently better than the target due to less than average number of storm and lightning-related fault impacts, static var compensator (SVC) transformer and reactive plant component issues.

Unplanned outage circuit event rate - Forced

A forced outage is any element outage that occurred as a result of 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.

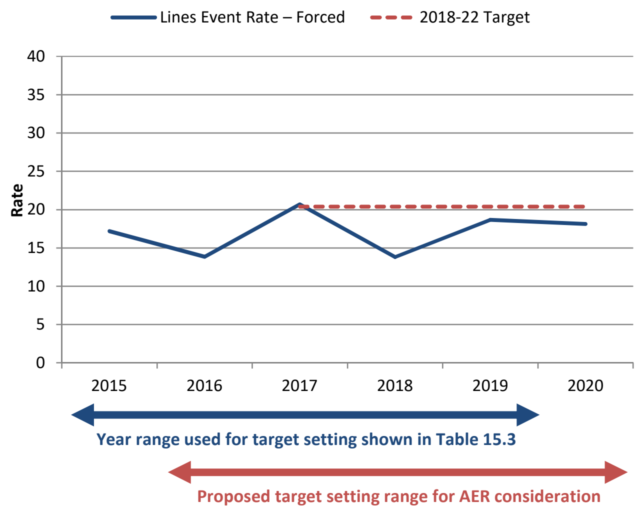
Similar to the fault outage rate, the forced outage circuit event rate parameter measures network reliability based on an aggregate number of forced outages per annum for each of the transmission element types (lines, transformers and reactive plant).

In 2018, we revised our approach by delaying our response to non-urgent conditions of high voltage plant where it was safe to do so, which provided more time for our customers to better plan and prepare their operations prior to an outage. This has reduced the number of occurrences of forced outage circuit rates across all categories.

The historical performance of our forced outage circuit rates since 2015 for transmission lines, transformers and reactive plant is shown in Figures 15.4, 15.5 and 15.6.

[11] For the first half of the 2017 calendar year (the end of our previous regulatory period) we were subject to the AER's 2011 STPIS (Version 3). For the second half of the 2017 calendar year (the start of the 2018-22 regulatory period), we were subject to the AER's 2015 STPIS (Version 5). We met our target for this sub-parameter for the second half of the 2017 calendar year.

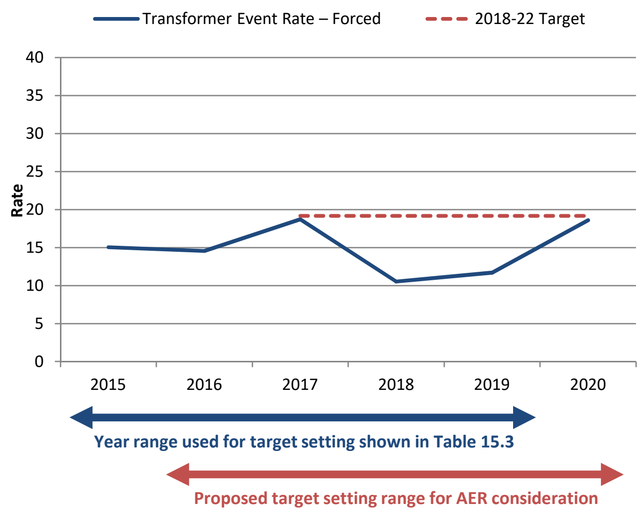
Figure 15.4: Lines event rate – Forced 2015-2020



The lines forced event rate performed better than the target, except for 2017, which was on target.

The number of specific issues requiring an outage with less than 24 hours notice to market participants was slightly below average. This includes issues such as marginal trees impacting line clearances and connection equipment issues such as a circuit breaker low gas condition.

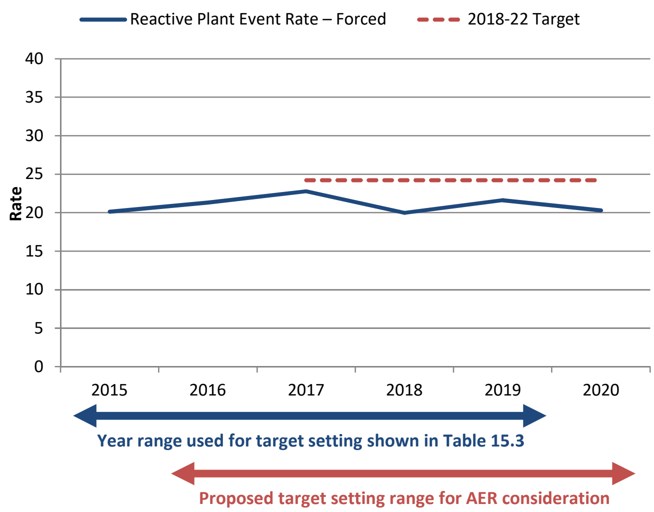
Figure 15.5: Transformer event rate – Forced 2015-2020



The transformer forced event rate sub-parameter performed consistently better than the target.

The number of specific issues requiring an outage with less than 24 hours notice to market participants was below average. This includes low oil level transformer related issues and connection equipment issues such as a circuit breaker low gas condition.

Figure 15.6: Reactive plant event rate – Forced 2015-2020



The reactive plant forced event rate performed well against the target.

The number of specific issues requiring an outage with less than 24 hours notice to market participants was slightly below average. This includes reactive element component related issues such as a capacitor bank out of balance condition or occurrence of SVC low cooling water condition and connection equipment issues such as a circuit breaker low gas condition.

Service Component performance – 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:

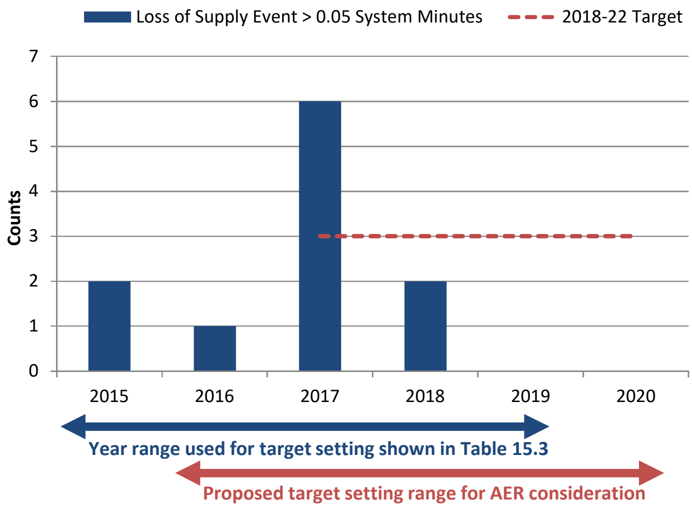
- the moderate event (x) threshold is a loss of supply event greater than 0.05 system minutes; and
- the large event (y) threshold is a loss of supply event greater than 0.40 system minutes.

For the 2023-27 regulatory period we remain subject to the same two sets of targets for loss of supply events as they can only be adjusted through a review and amendment of the STPIS. As outlined in Section 15.5.4, we have actively worked to minimise the impact of loss of supply events on our network. This has resulted in performance above the target for both moderate and large event thresholds.

Loss of supply event frequency greater than 0.05 system minutes (x)

Our historical performance for this parameter is shown in Figure 15.7.

Figure 15.7: Loss of supply event frequency greater than 0.05 system minutes (x) 2015-2020



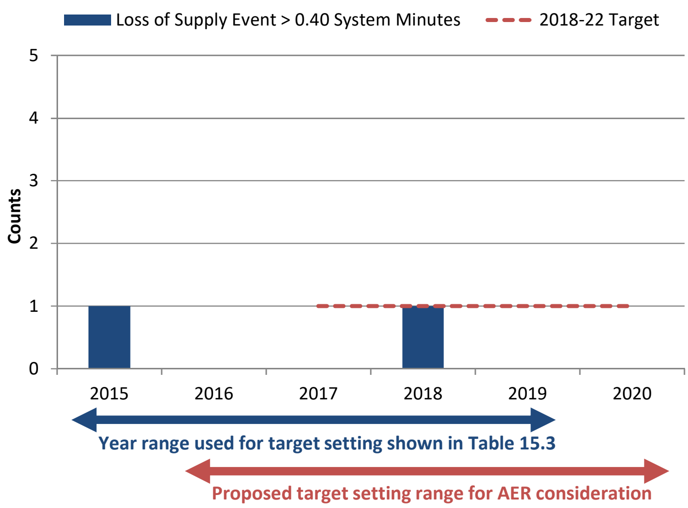
Overall we performed better than the target for the loss of supply event frequency sub-parameter under the moderate (x) threshold. This is a result of improvements to our established incident response processes such as targeted incident response training and simulation exercises, to minimise the impact of loss of supply on customers.

2017 was an outlier year where there was a higher than average number of events greater than 0.05 system minutes associated with outages and equipment faults.

Loss of supply event frequency greater than 0.40 system minutes (y)

Our historical performance for this parameter is shown in Figure 15.8.

Figure 15.8: Loss of supply event frequency greater than 0.40 system minutes (y) 2015-2020



We performed better than the target for the loss of supply event frequency sub-parameter under the large (y) threshold.

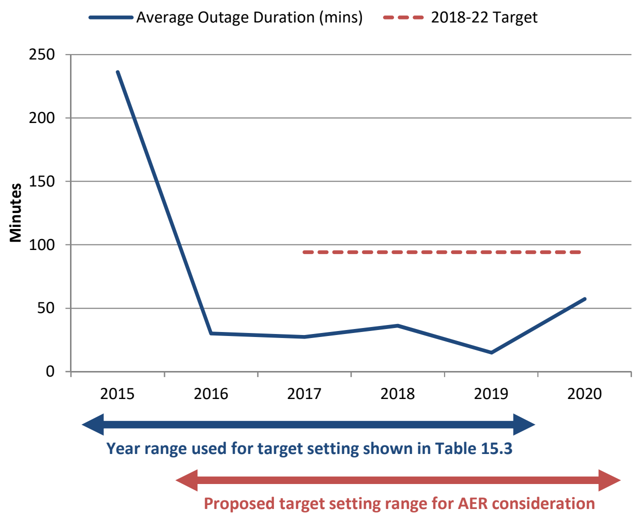
Since 2016, we experienced only one loss of supply event exceeding 0.40 system minutes. The one event occurred in 2018 and was a loss of both Chalumbin to Woree feeders due to lightning impact, which resulted in the loss of supply to Cairns and surrounding areas.

Service Component performance – 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 15.9.

Figure 15.9: Average outage duration 2015-2020



We performed better than the target for the average outage duration of loss of supply event parameter, due to a reduction in extended duration outages and outages associated with bulk supply points where supply could not be restored from alternative locations.

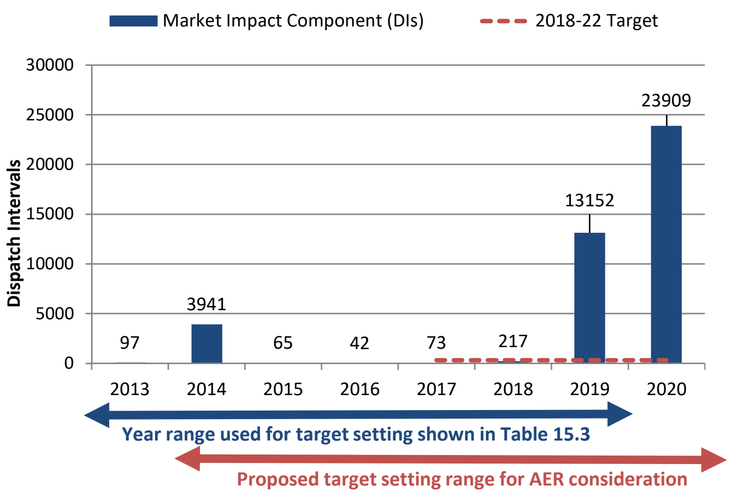
In 2015, a loss of supply event occurred which impacted a single directly-connected customer for an abnormally long duration.

15.4.2 Market Impact Component performance

The MIC measures the number of DIs where an outage on our network results in a network outage constraint with a marginal value greater than $10/MWh. Our MIC performance target for the 2018-22 regulatory period is 333 DIs per year.

As outlined in Section 15.3, our ability to manage network availability in the 2018-22 regulatory period has been challenged by significant changes to power flows and the generation mix, which have impacted system utilisation and constraints. This impact is evident from our historical MIC performance as shown in Figure 15.10.

Figure 15.10: Historical MIC performance 2013-2020



We performed well against the AER's target for the MIC up to the second quarter of 2019, as we consistently applied our established processes to minimise the impact of outage events.

In 2019, an unprecedented increase in DI counts was recorded for our network due to reductions in system strength, changes to generation topology and an increased penetration of non-synchronous generators. This trend has continued into 2020 despite our consistent application of enhanced processes to minimise the impact of outage events on market participants.

We continue to work closely with customers to plan and coordinate network outages at times least likely to result in a market constraint. We also take real-time action to reschedule works to reduce the impact of binding constraints on the market.

15.4.3 Network Capability Component performance

Under the NCC, we successfully completed our NCIPAP project at the end of 2018. This project was delivered at a cost of $0.4m.

The focus of our NCIPAP project was the Bouldercombe to Raglan and Larcom Creek to Calliope River 275kV circuits. These circuits form part of a transmission corridor that enables power flows between Central West Queensland and Gladstone.

Network constraints on this corridor were forecast to increase in the medium term[12]. We undertook works to increase ground clearances on 14 spans, which increased the design temperature of two 275kV transmission lines and ultimately enabled additional flexibility of dispatch to the NEM.

15.5 STPIS target setting for the 2023-27 regulatory period

This section sets out our proposed STPIS values and the approach we used to set our targets for the 2023-27 regulatory period. This is based on the Rules[13], the AER's 2015 STPIS and the AER's Final Framework and Approach for Powerlink[14].

15.5.1 Historical values for target setting

The AER's Reset RIN[15] stipulates the historical calendar years to be used to calculate our STPIS values for the 2023-27 regulatory period to be submitted in our Revenue Proposal and Revised Revenue Proposal. The AER's stipulated date ranges are:

- for the SC – 2015-19 (Revenue Proposal) and 2016-20 (Revised Revenue Proposal); and
- for the MIC – 2013-19 (Revenue Proposal) and 2014-20 (Revised Revenue Proposal).

We have urged the AER to reconsider these historical ranges as they do not reflect the latest historical year data i.e. it does not include the 2020 calendar year data, which is the most recent year data available for our Revenue Proposal, or the 2021 calendar year data for consideration as part of the AER's Final Decision in April 2022.

Our view is that the most recent historical data range ensures our STPIS targets more closely reflect the recent operating environment of the energy market, and enables the business to more meaningfully respond to the incentive and deliver benefits to our customers. This aligns with the AER's 2015 STPIS, which specifies that performance history over the most recent five years for the SC[16] and the most recent seven years for the MIC[17] be used to calculate the performance target.

Use of the most recent historical data to derive targets is particularly important for the MIC, due to the significant changes in our operating environment set out in sections 15.3 and 15.5.5. This is also demonstrated in Table 15.2, which compares the MIC target for the 2023-27 regulatory period without the most recent year data (the Reset RIN required 2013-2019 year range), and the MIC target with the most recent year data (the 2014-2020 year range). The comparison shows a significant difference that reflects the rapid changes in our operating environment.

Table 15.2: MIC target comparison

	2013-2019 Year Range			2014-2020 Year Range		
MIC Parameter	Performance Target	Unplanned Outage Event Limit	Dollar per Dispatch Interval Incentive	Performance Target	Unplanned Outage Event Limit	Dollar per Dispatch Interval Incentive
MIC	879	149	$7,673	3490	593	$1,933

The calendar year 2020 MIC performance result that Powerlink has provided in its 2023-27 Reset RIN Return (7.9 STPIS Alternative) and in our annual 2021 STPIS report submission is our estimate based on the Marginal Constraint Cost (MCC) data which was made available by AEMO on 15 January 2021. We will update the AER on any changes to the 2020 MCC as part of the AER's review of our Revenue Proposal prior to its Draft Decision. We will also update data in our Revised Revenue Proposal to be submitted in December 2021.

12 NEM Constraint Report 2014 Supplementary Data, Australian Energy Market Operator, April 2015.
13 National Electricity Rules, schedule S6A.1, clause S6A.1.3(2).
14 Final Framework and Approach Paper for Powerlink, Australian Energy Regulator, July 2020.
15 Reset RIN: Powerlink - clauses 11.1 and 11.2, Australian Energy Regulator, October 2020.
16 2015 STPIS, clause 3.2 (f).
17 2015 STPIS, Appendix F.

15.5.2 Proposed 2023-27 STPIS values

To ensure our Revenue Proposal complies with our Reset RIN, we have provided our STPIS values for the 2023-27 regulatory period based on the historical date ranges required by the AER in Table 15.3.

We have also provided the AER with two sets of data to inform its assessment:

- targets consistent with our Reset RIN; and
- targets based on our most recent historical data.

To inform the AER's assessment and its Final Decision, we will provide the AER with actual data for full calendar year 2021 in early 2022, including updated targets.

Table 15.3: STPIS values

SC Parameter (±1.25% Maximum Allowed Revenue (MAR))	Floor	Target	Cap	Distribution
Unplanned Outage Circuit Event Rate (±0.75% MAR)				
Lines event rate – Fault	23.85	18.92	14.85	Pearson5
Transformer event rate – Fault	25.09	18.07	10.44	Weibull
Reactive plant event rate – Fault	29.16	25.60	22.34	LogNormal
Lines event rate – Forced	21.00	16.83	11.85	Weibull
Transformer event rate – Forced	19.07	14.10	9.78	Gamma
Reactive plant event rate – Forced	22.80	21.18	18.92	Weibull
Loss of Supply Event Frequency (±0.30% MAR)				
Greater than 0.05 system minutes (x)	7	2	0	Geometric
Greater than 0.40 system minutes (y)	2(1)	1(1)	0	N/A
Average Outage Duration (±0.20% MAR)				
Average outage duration	147.17	69.00	7.91	LogLogistic

MIC Parameter (1.0% MAR)	Performance Target	Unplanned Outage Event Limit	Dollar per Dispatch Interval Incentive
MIC	879	149	$7,673
NCC Parameter(2)			
NCIPAP	No priority projects proposed, $0		

(1) The values derived from an alternative target methodology – refer Section 15.5.4.

(2) Pro-rata based allowance up to 1% MAR each year, with incentive of 1.5 times average annual project cost. Penalty of up to 3.5% final year MAR.

15.5.3 Proposed Service Component values

We have proposed targets, caps and floors for the relevant parameters and sub-parameters related to the SC based on Section 3.2 of the AER's 2015 STPIS.

The caps and floors were calculated on the basis of 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 15.01 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 our Revenue Proposal.

We have also proposed an alternative approach to set our target for the large (y) loss of supply (greater than 0.4 system minutes) sub-parameter, consistent with Section 3.2(i) of the AER's 2015 STPIS. Our reasons for this are explained further in Section 15.5.4.

We engaged WSP to review our methodology for setting floors and caps. WSP confirmed that we have used a robust methodology to determine the best fit statistical distributions. WSP also verified the actual statistical output from our statistical modelling and confirmed that the dataset meets the Version 5 requirements, as set out below:

> *In WSP's view this (Powerlink's) approach is robust, and does not seem to be sensitive to the choice of distribution function because the results were either close to the next best fit distributions or confirmed through close analysis of the underlying data. The approach is also consistent with the Australian Energy Regulator's previous regulatory decisions to use a curve of best fit approach*[18].

WSP's full report is included in Appendix 15.03.

15.5.4 Alternative Target Setting - Porposed large loss of supply event frequency

Under its 2015 STPIS[19], the AER can approve a performance target based on an alternative methodology proposed by the TNSP. We have proposed an alternative target setting approach for the large loss of supply event frequency. The following sections explain our reasons for this proposed alternative approach and why this alternative target meets the relevant NER requirements.

WSP considered that setting a target value based on a symmetric maximum revenue increment and decrement would be most consistent with the requirements of the Rules[20] and the AER's 2015 STPIS. Consistent with this, an adjustment of the system minutes threshold for this parameter would have been the most appropriate action.

In its report, WSP noted the AER's decision to not undertake a STPIS review at this time and, given this circumstance, WSP considered that the application of an alternative methodology as allowed for by the STPIS, would be appropriate[21].

Standard target setting approach for the large loss of supply event frequency

The large loss of supply event frequency floor and target is based on historical performance over the 2015-2020 period. Our event counts for the large loss of supply events measure is shown in Table 15.4.

Table 15.4: Event counts: loss of supply events 2015-2020

	2015	2016	2017	2018	2019	2020
Loss of Supply Event >0.4 System Minutes	1	0	0	1	0	0

The table shows that we experienced only one large loss of supply event in the most recent five years from 2016 to 2020. This strong performance means that the average of the most recent five years performance is anticipated to be 0.2. The five year average from the AER's required historical data range of 2015 to 2019 is 0.4.

The AER's 2015 STPIS[22] requires that targets are rounded to the nearest integer. This means that as a consequence of the improvements we have made over the 2018-22 regulatory period, there is potential for the threshold target for the large loss of supply event frequency measure to be set at zero events for the 2023-27 regulatory period.

One of the principles for the design of the STPIS is that it should provide incentives to maintain and improve the reliability of transmission network elements. We consider that a target of zero events does not support this principle.

We initially raised this issue with the AER in October 2019 as part of our request that it review and amend our Framework and Approach for the STPIS (SC and MIC). In its November 2019 response, the AER set out reasons why it considered a zero target is reasonable and invited us to submit an alternative target. As permitted under the AER's 2015 STPIS, we have therefore proposed an alternative target that we consider will better reflect the intent and design principles of the scheme.

On the issue of the zero target, our independent consultant WSP noted:

> *WSP does not consider that setting the target and cap to zero for the 'Large' loss of supply event frequency parameter is consistent with the requirements of the NER and STPIS as it does not provide incentive to improve reliability as set out by NER clause 6A.7.4(b)(1), nor does it enable the scheme to provide a maximum revenue increment of 1.25% MAR as required by STPIS clause 3.3(a).*

18 Statistical Validation of STPIS Service Component, WSP, January 2021, page 17.
19 2015 STPIS, clause 3.1(i).
20 National Electricity Rules, clause 6A.7.4(b).
21 Statistical Validation of STPIS Service Component, WSP, January 2021, pages 19-20.
22 2015 STPIS, Australian Energy Regulator, October 2015, clause 3.2(k).

Further, setting both the cap and target to zero reduces the maximum revenue increment that Powerlink may earn against the parameters and values to below the value of 1.25% MAR that is specified by the STPIS:

- *Clause 3.3(a) of the STPIS version 5 (Corrected) specifies that the maximum revenue increment or decrement a TNSP may earn against its parameters under the service component is 1.25% of MAR; and*
- *Clause 3.4(b) Table 3-1 of the STPIS sets the weighting for the large loss of supply parameter at 0.15% MAR.*

If zero incentive applies to the large loss of supply parameter, the maximum revenue increment provided for by the STPIS under this scenario is 1.1% of MAR and the maximum revenue decrement is 1.25%. This may not comply with the requirements of the STPIS, hence the cap, floor and target are not considered appropriate[23]*.*

We agree with WSP.

Our proposed alternative target

We propose that the performance target for the large loss of supply event frequency parameter be the average performance over the relevant five year period rounded to the nearest non-zero integer. This alternative methodology results in a target of one.

A comparison of the incentive payments under a target of zero against our proposed alternative target of one is contained in Table 15.5.

Table 15.5: Comparison of large loss of supply event incentive targets

Incentive target	Number of events		
	Zero	1	2
Zero	$0	Penalty of -0.15% of MAR (floor)	Penalty of -0.15% of MAR (floor)
1	Bonus of +0.15% of MAR (cap)	$0	Penalty of -0.15% of MAR (floor)

We consider that our proposed alternative target minimises the economic harm caused by large loss of supply events at an appropriate cost to customers. It sets an incentive for us to maintain a high standard of performance, maintains a symmetrical incentive and is consistent with the intent of the scheme.

We further explain the reasons why an alternative target is proposed below and show how this meets the requirements of the AER's 2015 STPIS.

Reasons for an alternative target

The STPIS is designed to provide incentives for service-level improvement and the delivery of benefits to customers. A zero target does not support this intent and the design principles of the scheme for the following reasons.

- It is not in the best interests of customers. The costs to maintain a performance level that is aimed to meet a zero target, which are ultimately borne by customers, would be higher compared to a lower target.
- A target of zero (i.e. the best possible performance level) undermines the incentive for a TNSP to continue to improve performance across all parameters in the scheme. The reason for this is that if a zero target is achieved, a TNSP would then be subject to a penalty-only incentive (or disincentive) for the relevant parameter/s in the future.
- The SC has applied symmetrically since the inception of the scheme. A target of zero would make the scheme asymmetric, as there is no scope for us to perform better than the target. We would only be exposed to downside risk as we would be penalised for any possible loss of supply events (above the floor). Effectively, it becomes a penalty only scheme. This would undermine the intent and purpose of the scheme, which is to incentivise TNSPs to improve and maintain reliability[24].

[23] Statistical Validation of STPIS Service Component, WSP, January 2021, page 19.
[24] National Electricity Rules, clause 6A.7.4(b).

The AER has previously noted that the S-factor (or service factor) is symmetrical, i.e. penalties are incurred at the same rate as rewards[25]. In its development of the 2017 STPIS (Version 2) for electricity distribution, the AER confirmed that the STPIS is a symmetrical scheme that provides a direct link between a Distribution Network Service Provider's (DNSP's) revenue and the standard of service provided[26].

This was also supported by stakeholders. While these statements have been made in the context of distribution they are equally applicable to TNSPs and the AER's 2015 STPIS[27].

This is shown by the S-curve (reverse) charts below. They compare our proposed target of one, which retains a symmetrical rate of incentive payments (refer to Figure 15.11) against the scenario where the performance target is set at zero (refer to Figure 15.12).

Figure 15.11: Symmetrical scheme - target set at one

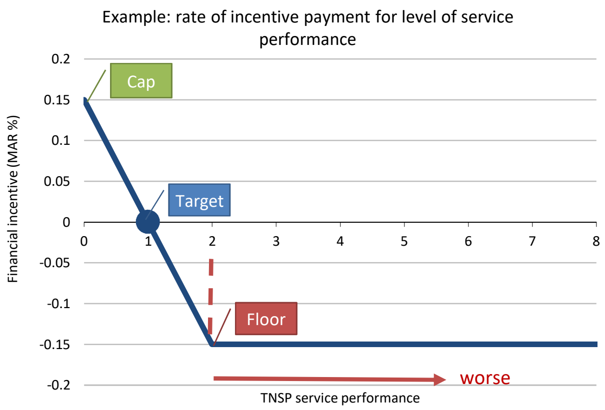
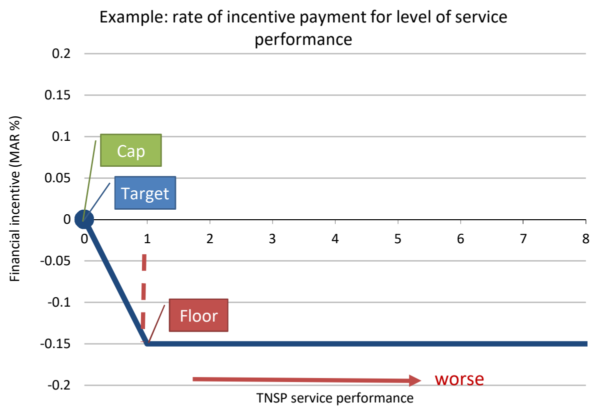


Figure 15.12: Asymmetrical scheme - target set at zero



Consideration of the 2015 STPIS requirements

We summarise how our alternative methodology meets the requirements of Section 3.2(i)(1) to (5) of the AER's 2015 STPIS in Table 15.6.

In addition to our assessment below, WSP undertook an independent evaluation of our proposed alternative target setting methodology against the requirements of the AER's 2015 STPIS and the Rules. For ease of reference, WSP's assessment from its report is also included in the table[28].

25 Explanatory Statement and Discussion Paper: Proposed Electricity Distribution Network Service Providers Service Target Performance Incentive Scheme, Australian Energy Regulator, April 2008, pages 14-15.

26 Explanatory Statement: Service Target Performance Incentive Scheme, Australian Energy Regulator, December 2017, page 25.

27 The 2015 STPIS defines the S-factor as 'the percentage revenue increment or decrement that the maximum allowed revenue is adjusted by in each regulatory year based on a TNSP's performance in the previous calendar year.'

28 Statistical Validation of STPIS Service Component, WSP, January 2021, pages 21-23.

Table 15.6: Assessment of alternative target against the AER's 2015 STPIS

Consideration	Powerlink position	WSP assessment
The methodology is reasonable.	The standard methodology to set targets under the AER's 2015 STPIS is to use the average of five years of history. For the loss of supply event frequency parameters the performance target is rounded to the nearest integer. Our proposed methodology retains this design feature, and ensures that a symmetrical scheme is maintained at high levels of performance. This maintains the incentive properties of the scheme. We consider this is reasonable and consistent with the intent of the STPIS.	WSP considers that the methodology is reasonable as it targets the specific issue and will only affect the outcome in the situation where the average of the past performance is less than 0.5 events per year. In any other case, rounding to the nearest integer (the standard calculation) and rounding to the nearest non-zero integer will result in the same outcome.
The TNSP's performance as measured by the relevant parameter has been consistently very high over every calendar year of the previous five years.	As shown in Table 15.4, we have performed at a consistently high level and only experienced one large loss of supply event over the last five years.	Powerlink has performed highly during the past five calendar years, exceeding their target in three years and meeting the target in two. Hence this clause is satisfied.
It is unlikely that the TNSP will be able to improve its performance during the next regulatory control period (or any potential improvement would be marginal), or any further improvements are likely to compromise the TNSP's other regulatory obligations.	If the target is set at zero, this is the highest possible performance level. In actual terms, compared to the one large event experienced over the most recent five calendar years, the only improvement we could make is to have zero large events in every year of the 2023-27 regulatory period. The achievement of this outcome would require expenditure that outweighs the benefits to customers.	It is unlikely that Powerlink would be able to improve its performance significantly, and cannot improve it beyond the target that would be set by the standard calculation methodology, hence the lack of incentive described in the sections above.
Where applicable, the TNSP's proposed performance targets are not a lower threshold than the performance targets that applied to an identical parameter in the previous regulatory control period.	The alternative target proposed is no lower than the performance targets that have previously been set for this parameter.	The performance target in the current regulatory control period is one with a cap of zero and a floor of two. Hence, the proposed values are the same as for the current period and are not lower.
The proposed methodology is consistent with the objectives in clause 1.4 of the scheme.	To support the National Electricity Objective (NEO), it is important that the methodology results in incentives to maintain efficient operation in the long-term interests of consumers. The proposed methodology is also consistent with the objectives set out in clause 6A.7.4(b) of the Rules, which are that the STPIS provide incentives to improve and maintain the reliability of network elements.	The proposed methodology ensures: There is a cost neutral position over the long-term to allow for natural variation around the average, hence promoting prudent and efficient expenditure decisions and consistency with STPIS clause 1.4(a)(1) and STPIS clause 1.4(b)(3). There is incentive to improve performance and therefore is consistent with STPIS clause 1.4(a)(2). There is a transparent calculation approach and is therefore consistent with STPIS clause 1.4(b)(1) and (2). *Note: WSP also undertook a more detailed assessment of consistency under clause 6A.7.4, which is included in its report* (1).

(1) Statistical Validation of STPIS Service Component, WSP, January 2021, pages 21-23.

15.5.5 Proposed Market Impact Component target values

We have proposed our performance target, unplanned outage event limit and dollar per dispatch interval incentive for the MIC based on the AER's 2015 STPIS[29]. Our approach is consistent with the AER's methodology in Appendices C and F of its 2015 STPIS. Appendix 15.01 Setting STPIS Values includes detailed information on the calculations for this parameter.

[29] 2015 STPIS, Section 4.2.

We have also based our target values for the MIC on historical performance for the 2013-2019 period, shown in Section 15.4.2. As noted in Section 15.5.1, we have urged the AER to use data to 2020 as the proposed target setting range.

The changes we have observed to power flows and the generation mix in the current regulatory period, which have been experienced across the NEM, was the key reason for our request to the AER to review the STPIS (refer Section 15.3.1). This proposal was supported in principle by our customers, noting that adequate consultation would need to occur as part of the review[30].

We remain concerned about the AER's continued use of our historical performance to set our future MIC targets, and the use of data that does not capture the most recent year's performance. In our correspondence to the AER[31] we explained that if our actual/forecast performance for the MIC between 2015 and 2021 is used to set the target for the 2023-27 regulatory period, we would likely exceed the maximum penalty for that entire period. This reflects the impact of the growth in DI counts that only emerged in 2019, as shown in Figure 15.10.

In response to a request from the AER, we provided more detailed analysis of why the MIC counts increased in 2019. We also provided analysis to support our expectation that this MIC count will increase in future, which we attribute to three main drivers:

- Central Queensland–Southern Queensland (CQ-SQ) intra-regional flows: this will increase periods of constraint;
- system strength constraints: an outcome of the increased asynchronous generation built across the network, which was not initially designed for this outcome; and
- localised generation constraints: this is manifest through the locations of new renewable generation.

The AER has advised that it considers that the MIC operates appropriately under the AER's 2015 STPIS[32]. Unlike the SC, the AER's 2015 STPIS does not allow us to propose an alternative methodology to set the performance target for the MIC.

While the use of historical performance data to set our MIC target remains a concern for us, we have calculated our target for the 2023-27 regulatory period consistent with the methodology in Appendices C and F of the AER's 2015 STPIS[33].

15.5.6 Proposed Network Capability Component projects

The NCC is intended to facilitate improvements in the capability of transmission assets through operational expenditure and minor capital expenditure. Under the AER's 2015 STPIS, we may submit a Network Capability Incentive Parameter Action Plan (NCIPAP)[34] to facilitate these improvements.

Our approach to NCIPAP is to only propose projects that provide genuine customer and market benefits, which meet the objectives and criteria of the NCC[35]. To determine whether there are any potential projects that meet this criteria to be put forward in our Revenue Proposal, we carried out an internal process to identify, review, validate and rank a broad range of potential candidate priority projects. We initially identified 12 potential projects for review and shortlisted three credible candidate priority projects.

Broadly, the three shortlisted projects would potentially result in increased operating limits on selected transmission lines, assist with the provision of operational data and increase grid transfer capacity. We then undertook a more detailed internal review and validation of customer benefits, which included consultation with AEMO. This review resulted in the identification of a range of technical issues associated with each project that may impact their potential market/customer benefits.

As a result, we consider that these issues need to be better understood and require more analysis and timing/technology alignment prior to the progression of a NCIPAP. We have therefore decided not to include any NCIPAP projects in our Revenue Proposal.

We may pursue potential projects within the 2023-27 regulatory period if they become viable, based on the AER's 2015 STPIS. To facilitate this, in we have amended our annual asset management processes to include routine potential NCIPAP project reviews to ensure we consider, and where appropriate propose, NCIPAP projects for implementation.

30 Meeting minutes of January and February 2020 Revenue Proposal Reference Group (RPRG), Powerlink, https://www.powerlink.com.au/2023-2027-regulatory-period.
31 Proposed STPIS review, Powerlink, Australian Energy Regulator, January 2020.
32 Framework and Approach: Powerlink, Australian Energy Regulator, July 2020, page 12.
33 2015 STPIS, Appendix C Market Impact Component – Definition, Appendix F Market Impact Component - Application.
34 2015 STPIS, Section 5.2(b).
35 2015 STPIS, Section 5.2.

We will make a request to the AER as part of our annual STPIS reports during the 2023-27 regulatory period[36], if we consider that any of the three shortlisted projects or any other NCIPAP project would meet the STPIS requirements and provide benefit to customers. This will involve consultation with AEMO, the AER and our customers and stakeholders.

15.6 Summary

Our STPIS performance for the 2018-22 regulatory period demonstrates the improvements that we have made to deliver safe and reliable network services to meet the needs of our customers.

Over this period the impact of changes in our operating environment and energy market has become more evident. This includes the challenges that have arisen from the constraints experienced as a result of the rapid change in the mix and location of generation. This has particularly impacted the MIC.

As provided for under the AER's 2015 STPIS, we have proposed an alternative target for our large loss of supply event frequency parameter. Our proposed alternative target better reflects the intent and design principles of the scheme, and targets a higher level of performance than our 2018-22 target for this parameter.

We have provided the AER with two sets of data to inform its assessment of our Revenue Proposal and its Draft Decision:

- targets consistent with our Reset RIN; and
- targets based on our most recent historical data.

To inform the AER's assessment and its Final Decision, we will provide the AER with actual data for full calendar year 2021 in early 2022, including updated targets.

[36] Consistent with the AER's 2015 STPIS, clause 5.4 (b).

16. Pricing Methodology

16.1 Introduction

This chapter presents information on Powerlink's Proposed Pricing Methodology for the 2023-27 regulatory period and proposed amendments to our current approved methodology.

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 charges.

A marked-up copy of our Proposed Pricing Methodology, which shows changes from our current Pricing Methodology, is provided in Appendix 16.01.

Key highlights

- We have undertaken a review of our transmission pricing arrangements. This involved a range of customer engagement activities since April 2018, to inform our Proposed Pricing Methodology.
- Our Transmission Pricing Consultation concluded in November 2020, after publication of a Final Positions Paper.
- We have proposed one key amendment to our existing Pricing Methodology as a result of our Transmission Pricing Consultation. This amendment will progressively transition customers to locational charges based on peak demand only. This transition will occur over the next two regulatory periods (or 10 years), commencing 1 July 2022.
- We also propose five other minor amendments to our existing Pricing Methodology to:
  - adjust the non-locational component of prescribed transmission use of system services (TUOS) by the advised National Transmission Planner (NTP) costs each year;
  - reference the National Electricity Rules (the Rules) regarding the calculation of payments between multiple Transmission Network Service Providers (TNSPs) in Queensland;
  - improve clarity in the application of excess demand charges;
  - clarify consistency with the AER's Pricing Methodology Guidelines regarding postage-stamped prices and prudent discounts; and
  - update the timeframe for publication of the Modified Load Export Charge (MLEC).

16.2 Regulatory requirements

The Rules[1] require us to submit a Proposed Pricing Methodology with our Revenue Proposal. The Rules also specify the requirements for a Pricing Methodology[2], which include consistency with the pricing principles for prescribed transmission services[3], the Australian Energy Regulator's (AER's) 2014 Transmission Pricing Methodology Guidelines[4] and any relevant regulatory information instrument.

16.3 Our Proposed Pricing Methodology

16.3.1 Review of pricing arrangements

We recognise affordability remains a key concern for our customers, both our large-scale directly-connected customers and end-users. We consider it vital that all parts of the electricity system, including transmission, play their role in trying to address affordability concerns and put downward pressure on prices.

We know our customers are changing the way they use the transmission network, as transformational changes take place throughout the electricity system (refer Chapter 2 Business and Operating Environment). Our challenge is to find ways to adapt to the changing environment and deliver our transmission services to meet customer expectations at the lowest long-run cost.

In early 2018, we commenced a review into our transmission pricing arrangements[5]. This review was prompted by customer input and changing expectations. We put forward a number of potential alternative pricing options which could be included as part of changes to our Proposed Pricing Methodology for the 2023-27 regulatory period or addressed more broadly through the Rules framework.

1 National Electricity Rules, clause 6A.10.1.
2 National Electricity Rules, clause 6A.24.
3 National Electricity Rules, clause 6A.23.
4 Pricing Methodology Guidelines, Australian Energy Regulator, 2014.
5 Transmission Pricing Consultation Process, Powerlink, https://www.powerlink.com.au/transmission-pricing-consultation-process.

The review focused on how we can enhance the role of transmission pricing arrangements to:

- provide stronger signals to customers to encourage more efficient use of the network, which lowers future network costs; and
- enable customers to reduce their costs by changes to their network usage.

Further detail on the proposed changes to our Pricing Methodology, our approach to the review, and customer and stakeholder input that informed the proposed changes, is outlined in sections 16.3.2 and 16.3.3.

16.3.2 Customer and stakeholder engagement

We engaged with a broad range of stakeholders as part of our Transmission Pricing Consultation. This included our Customer Panel, Energy Queensland (Energex and Ergon Energy) and customers connected directly to its distribution networks, other TNSPs and other directly-connected customers.

In addition to informal discussions with customers, key engagement milestones included:

- Customer Panel – held 19 April 2018;
- Transmission Pricing Webinar – held 11 May 2019;
- Transmission Pricing Consultation Paper (Appendix 16.02) – published 26 July 2019;
- Draft Positions Paper (Appendix 16.03) – published 26 August 2020; and
- Final Positions Paper (Appendix 16.04) – published 18 November 2020.

A description of these engagement activities are summarised in Table 16.1. We established a dedicated page on our website to provide information on our transmission pricing consultation, copies of our papers and a contact point for any feedback[6].

After the release of our Transmission Pricing Consultation and Draft Positons Papers, we offered our directly-connected customers the opportunity for one-on-one discussions. In total, we held 17 individual discussions of around one to two hours each with the majority of our directly-connected customers. The format of these discussions enabled customer-specific information about the impact of potential alternative pricing arrangements to be discussed openly and in more detail. It gave customers a further opportunity to clarify their understanding of what was being proposed and what this could mean for their individual business circumstances. Our customers acknowledged the enhanced transparency of this format and many welcomed and appreciated the time we took to enable tailored discussions to occur.

Further to the consultation specific engagement above, in the normal course of business, we engage regularly with the 20 or so directly-connected load customers for whom transmission pricing and billing is a key issue. Our customers, including generators, proactively bring any concerns to us for consideration either within or outside a formal consultation process. This input was one of the drivers for us to undertake a review of our transmission pricing arrangements.

We also updated our Transmission Pricing Overview document and released an introductory video on transmission pricing[7] on a webpage dedicated to helping our customers better understand transmission pricing arrangements. These were commitments we made to customers in The Energy Charter.

6 Transmission Pricing Consultation Process, Powerlink, https://www.powerlink.com.au/transmission-pricing-consultation-process.

7 Understanding Transmission Pricing, Powerlink, https://www.powerlink.com.au/understanding-transmission-pricing.

Table 16.1: Summary of engagement activities

Activity	Description
Customer Panel discussion	In April 2018, our Customer Panel provided input into a review of potential alternative pricing arrangements. We acknowledged that engagement was very early in the process. We discussed and sought initial feedback on the scope and purpose of the review, workshopped potential pricing objectives and introduced potential options to guide the forthcoming Transmission Pricing Consultation Paper.
Transmission Pricing Consultation Paper	We published a Consultation Paper in July 2019. To allow for a broad range of views, this Consultation Paper identified 10 possible alternative pricing options that centred around four key pricing areas, namely: • alternatives to Cost Reflective Network Pricing (CRNP); • improving how transmission customers are charged; • peak and off-peak charging; and • other initiatives. We sought early input into this paper via our Customer Panel, an open webinar with approximately 14 customer representatives, and through discussions with other TNSPs via Energy Networks Australia (ENA). We also held discussions with Energy Queensland to understand ways to better align the structure of transmission charges and distribution tariffs. We incorporated this feedback in the Consultation Paper. We received limited feedback on the Consultation Paper. Many customers advised that they would prefer further detail on their individual pricing impacts before they could comment. Most customers advised that they were open to further discussion on potential changes to the transmission pricing arrangements. Generally, our customers acknowledged the principles behind advancing cost-reflectivity. A summary of feedback received from stakeholders is included in Table 16.3.
Draft Positions Paper	In August 2020 we published our Draft Positions Paper. This built on the pricing criteria and potential options discussed in the Consultation Paper. It also discussed the feedback received on our Consultation Paper and the actions we undertook in response. This feedback also informed the refinement of the potential alternative pricing arrangements to four options for more detailed consideration, outlined in Table 16.2. These options were evaluated against three pricing criteria proposed in our Consultation Paper: • equity and fairness; • price stability and transparency; and • efficient price signals. We modelled in more detail individual customer impacts of the alternative pricing options, which enabled more tailored follow-up discussions with customers and stakeholders. Given the confidential nature of individual customer information, the Draft Positions Paper provided a high level overview of these outcomes. This included, for each option, an indication of the following impacts in both dollar and percentage terms for customers: • highest and lowest; • average Distribution Network Service Providers (DNSPs); and • what 80% of directly-connected customers would observe. A summary of feedback received from stakeholders is included in Table 16.3.
Final Positions Paper	In November 2020 we published our Final Positions Paper. The purpose of this paper was to advise customers and stakeholders of the outcome of our Transmission Pricing Consultation. The paper: • summarised discussions and feedback received; • described how engagement influenced our final positions; and • identified what changes we intend to make going forward and how they will be progressed. Based on the options canvassed during the consultation, our Final Positions Paper proposed one key amendment to our existing Pricing Methodology to progressively transition customers to locational charges based on peak demand only. This transition will occur over two regulatory periods (or 10 years), commencing 1 July 2022. Further information on the evaluation of customer feedback and how this informed the proposed amendment is discussed in Section 16.3.3. As a result of our engagement with customers, we also concluded that there would be benefit in undertaking further discussions with customers on MVA charging and to explore potential options to relax the annual side constraint on movements in locational prices in the future. These discussions will occur in the normal course of business.

16.3.3 Key changes to our Pricing Methodology

Options considered

The four options considered in our Draft Positions Paper are summarised in Table 16.2.

Table 16.2: Pricing options presented in the Draft Positions Paper

Option	Description	Permitted under the current Rules?
1. Rebalancing the locational and non-locational split to 60/40	Currently the Rules(1) require an allocation between locational and non-locational charges based on either: • a 50% split between each component (our current approach); or • an alternative that reflects future network utilisation and the likely need for future transmission investment. This option implements an alternative that would increase the weight applied to locational charges to 60%. This would strengthen the link between peak demand and utilisation. This is a first step to further enhance the cost reflectivity of transmission charges.	Yes.
2. Locational charges based on peak demand only	Currently the structure of our locational charges are based on a 50/50 split between peak demand and average demand. However, locational revenue requirements are calculated during periods of peak usage of the shared network. This option would remove the average demand component from our charging structure. This will mean that our locational charges and revenue requirements would be determined on a consistent basis.	Yes.
3. MVA charging	MVA is a measure of electricity that accounts for how loads use the transmission network. It is a 'complete' measure of power flow as it captures reactive power. Given reactive power is not as easily transported over long distances, loads that draw more reactive power will also require more network investment. MVA charging would improve the cost reflectivity of transmission charges as charges would vary depending on each load's reactive power efficiency. This means that less efficient loads would face a higher charge, which signals the additional investment required to service them.	No. This would require a Rule change.
4. Accounting for the side constraint	The side constraint operates to protect customers from price shocks. It limits the rate of change of locational charges between years to between 2% of the load-weighted average for Queensland. The trade-off is that it may dilute locational price signals to customers. A more dynamic side constraint could increase the efficiency of locational charges as it would allow more direct price signals.	No. This would require a Rule change.

(1) National Electricity Rules, clause 6A.23.3(a)(2).

Customer input and response

We received customer input on our Transmission Pricing Consultation Paper and our Draft Positions Paper. We also sought feedback from customers on whether they considered that any other changes were required to our Pricing Methodology or other pricing arrangements beyond those proposed in our consultation papers. This feedback and our response is summarised in Table 16.3.

Following discussions with our customers as outlined in Section 16.3.2 we received 10 submissions in response to our Draft Positions Paper. Five of these were formal submissions and five other stakeholders provided input by email. Appendix 16.05 Submissions to Powerlink's Transmission Pricing Consultation Paper provides a copy of these submissions[8].

[8] Note that six submissions are public, two are confidential to the Australian Energy Regulator (AER) only and two are confidential to Powerlink only.

Table 16.3: Summary of general customer input and response

Input received	Powerlink response
Transmission Pricing Consultation Paper	
General agreement with the pricing criteria, acknowledging its 'give and take' nature.	Proposed pricing criteria will be used to understand the interaction with alternative pricing arrangements.
Need more details about individual customer impacts prior to providing formal responses.	Conducted modelling at an individual customer level on the four options to provide greater detail. Offered to engage with individual customers to discuss direct impacts.
Questioned the usefulness of enhancing demand based pricing signals in the current low growth environment.	The Draft Positions Paper provided further information on a range of options including alternatives to those which wholly impact demand signals.
Acknowledge the complex nature of transmission pricing but prefer that the next consultation papers be as brief as possible.	The Draft Positions Paper was concise with information and modelling presented at a high level. We offered to have detailed discussions with individual customers and stakeholders during the consultation period.
Valued the nature of individual discussions and information could be tailored to how individual customers use the network.	To balance the ongoing transparency of this consultation against the sensitive nature of individual customer impacts, we will engage with the wider audience and continue direct discussions with our directly-connected customers.
Acknowledge the principles behind increasing cost reflectivity noting that there are limitations to how far this can be progressed.	The majority of options included in the Draft Positions Paper advance cost reflectivity in a way which can be furthered in the future.
Draft Positions Paper	
Loads have the capability to achieve similar outcomes (increased efficiency through transmission pricing arrangements) from other avenues (changes in customer behaviour) without the need for fundamental pricing reform.	We intend to progress with further engagement on MVA charging through other work streams outside our revenue determination process.
A clear transitional path should be included with any change, mindful of customer impacts.	We have proposed a transitional pathway over two regulatory periods in relation to locational charges being based on peak demand only.
Impacts of any change on the wider customer base should be considered in the overall outcome.	Our final position to move to locational charges based on peak demand only will be gradual, which should limit impacts on the wider customer base.
Proposals considered are significant, given the timing of broader reviews currently occurring (for example, the Coordination of Generation and Transmission Investment (COGATI) Review and Energy Security Board's (ESB's) Post 2025 Review). Material changes now may lead to unexpected outcomes.	Our final positions do not propose fundamental changes to the existing pricing framework. We will engage with customers and stakeholders again and seek wider customer support before progressing broader pricing framework changes like relaxation of the locational price side constraint.
Overall, support no change to pricing arrangements. The current pricing methodology provides a reasonable basis for price allocations.	As above.
Powerlink should focus on reducing the overall cost burden for all customers.	Powerlink's Revenue Proposal recognises that affordability remains a key concern for customers. We have proposed a target of no real growth in our operating expenditure and a 3% reduction in our capital expenditure in the 2023-27 regulatory period, compared to the current period. These forecasts, combined with a reduction in our Regulatory Asset Base (RAB) and Rate of Return (RoR), are the drivers of our forecast 11% nominal reduction in the indicative transmission price in the first year of the 2023-27 regulatory period and on average, increases over the remainder of the regulatory period to be within inflation (refer Chapter 11 Maximum Allowed Revenue and Price Impact).
The application of the side constraint appears to operate in conflict with the objectives of cost reflective network pricing in the current market transition.	We recognise the impact that the side constraint has on efficient pricing particularly in periods where higher levels of change are expected. We plan to engage further with customers on what alternative options for relaxing the side constraint would look like and if these arrangements would lead to better outcomes for customers.

Final Positions

Of the four alternative pricing options considered in the Draft Positions Paper two are currently allowed under the Rules[9] and could potentially be implemented in our Proposed Pricing Methodology for the 2023-27 regulatory period. These options were rebalancing the locational and non-locational split to 60/40 and locational charges based on peak demand only.

We received valuable feedback on our Draft Positions Paper specific to the individual options posed. The Final Positions Paper[10] described how this feedback influenced our decision-making, which are summarised below.

Rebalancing the locational and non-locational split to 60/40

We have decided not to progress this change in our Proposed Pricing Methodology for the 2023-27 regulatory period.

Customers understood the link between enhanced efficiency of transmission prices and a higher weighting of locational charges. However, they also recognised that practical limitations exist and these need to be considered in adapting to a change in locational price signals. One of the key reasons for our pricing review was to enable customers to reduce their electricity costs by changing their utilisation of the network.

In making the decision not to progress with this option, we acknowledged customer feedback that highlighted their limited ability to react to a locational price signal, particularly where customers have already located (and sunk costs). Some considered that locational price signals were already appropriate. Combined with relatively flat demand growth forecast over the 2023-27 and subsequent regulatory periods, we considered there would be limited benefit in allocating a higher proportion of transmission charges to locational at this stage.

Locational charges based on peak demand only

We have decided to progress this change in our Proposed Pricing Methodology for the 2023-27 regulatory period. This will include a mechanism to phase in the change to locational prices being based on peak demand only. This transition will occur gradually over 10 years (or two regulatory periods), commencing 1 July 2022.

There are a number of benefits in this proposed change. In particular, the change would better align how customers are charged with locational price calculation principles in the Rules. That is, that they be based on demand at times of greatest utilisation of the transmission network for which network investment is most likely to be contemplated[11]. Peak rather than average demand is a key consideration in network investment. Phasing out the average demand component would also provide a stronger, simpler link between each customer's peak usage of the transmission network and what they are billed each month. It would also better align our pricing structures with those applied by other TNSPs.

Fundamentally the change does not alter the methodology for allocating locational revenues[12] that we currently apply. The side constraint limits the rate of change in the locational price between years[13]. All things being equal, once the locational price reflects the new charging arrangement, the same amount of locational revenue is recovered.

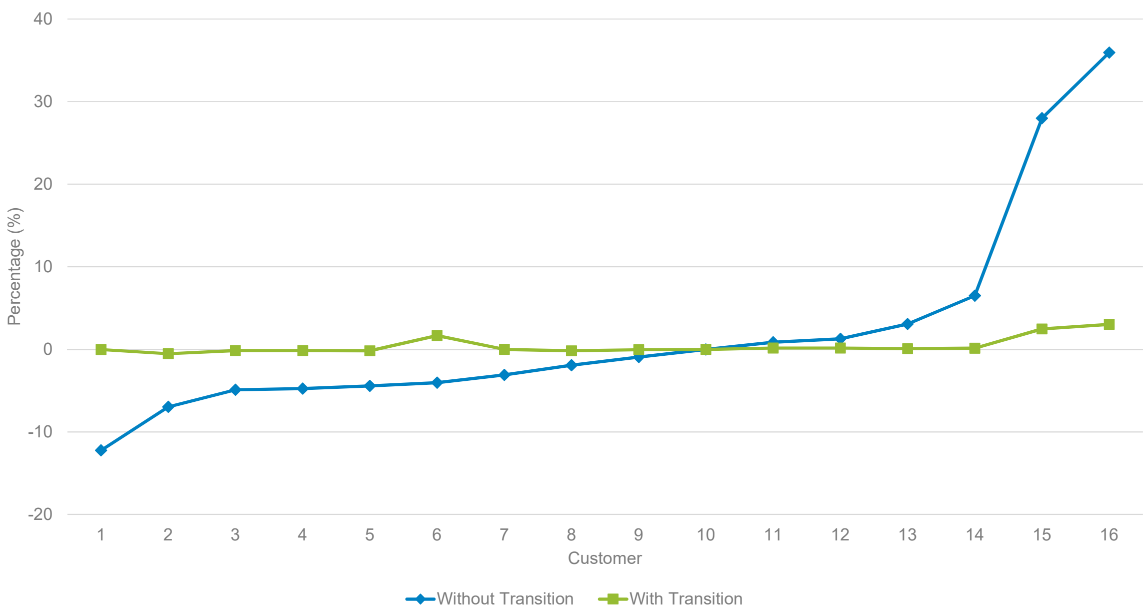
The AER's Pricing Methodology Guidelines allow transitional arrangements to be proposed where necessary[14]. We have proposed to implement this change over a 10 year transition period. We consider that a transitional arrangement to reduce the average demand component by 10% per year is reasonable to minimise unintended[15] price impacts and to allow time for customers to better understand and prepare for this change.

For illustrative purposes, Figure 16.1 shows the impact on directly-connected load customer charges as a result of removing the average demand component of locational prices, with and without the proposed transition mechanism. The impacts have been modelled on the basis of revenue, customer demand and energy input assumptions that underpinned our prescribed transmission prices for 2020/21. The 'with transition' line shows the customer impact (customers 1 to 16) in the first year of the 10 year transition period, which assumes 90% of average demand is considered. We expect the impact on customers in each of the remaining 9 year transition to be similar, noting that the 2% side constraint on movements in locational prices is assumed to remain in place. To the extent the side constraint remains an issue at the end of the transition period, the Rules provide customers with the opportunity to have their locational price recalculated[16].

9 Table 16.2 and National Electricity Rules, clauses 6A.23.3(a)(2) and 6A.23.4(b)(1).
10 Final Positions Paper Powerlink, Section 3.
11 National Electricity Rules, clause 6A.23.4(b)(1).
12 Using Cost Reflective Network Pricing (National Electricity Rules, clause S6A.3.2) and TPRICE (industry standard transmission pricing software).
13 National Electricity Rules, clause 6A.23.4(b)(2).
14 Pricing Methodology Guidelines, Australian Energy Regulator (AER), 2014, Section 2.1(j).
15 By application of the side constraint.
16 National Electricity Rules, clause 6A.23.4(b)(3)(ii).

This arrangement is expected to reduce the annual variation in revenues allocated[17] and collected. To be clear, the total amount we forecast to recover from each customer each year will not be materially impacted.

Figure 16.1: Indicative customer impact with and without transition



As a direct result of the change, we also expect there to be minimal price impact on residential and small business customers.

16.3.4 Other minor changes to our Pricing Methodology

We have put forward five other minor amendments to our Proposed Pricing Methodology (refer to Appendix 16.01) to reflect recent regulatory developments and to improve clarity. These include:

National Transmission Planner (NTP) Fee

Prior to commencement of the Integrated System Planning Rule[18], costs incurred by the Australian Energy Market Operator (AEMO) in relation to its NTP function were recovered from market customers. The Rule resulted in a reallocation of AEMO's NTP function fees to TNSPs from 1 January 2021.

We currently forecast a NTP cost allocation to Queensland of approximately $7.0m per annum (nominal 2020/21)[19]. The Rules require that the non-locational component of prescribed TUOS be adjusted for the amount of NTP function fees advised by AEMO[20]. For clarification, these fees do not form part of our Revenue Proposal.

This amendment is reflected in Section 6.8.3.2 of our Proposed Pricing Methodology.

Calculation of payments between multiple TNSPs

Powerlink is currently the sole provider of prescribed transmission services in Queensland. In the event that these services are provided by more than one TNSP in Queensland, financial transfers determined by the Co-ordinating Network Service Provider may be required. The process for the calculation of these transfers is outlined in the Rules[21].

This amendment is reflected in Section 7.2 of our Proposed Pricing Methodology.

17 Using Cost Reflective Network Pricing (National Electricity Rules, clause S6A.3.2) and TPRICE (industry standard transmission pricing software).
18 The National Electricity Amendment (Integrated System Planning) Rule 2020, (April 2020).
19 Forecast allocation based on NTP function fees forecast in AEMO's 2020-21 Budget and Fees.
20 National Electricity Rules, clause 6A.23.3(e)(6).
21 National Electricity Rules, clause 6A.27.5.

Excess Demand Charges

The AER's Pricing Methodology Guidelines[22] and our Pricing Methodology require that where a customer's actual maximum demand exceeds the contract agreed maximum demand, excess demand charges apply. In practice, revenue recovered through incremental charges from customers that have an exceedance event reflect the increase for the whole financial year.

This amendment is reflected in Section 6.11 of our Proposed Pricing Methodology.

Consistency with AER's Pricing Methodology Guidelines

We have identified two areas to clarify consistency with the AER's Pricing Methodology Guidelines in our Proposed Pricing Methodology. These changes clarify that:

- in deciding whether the energy or contract agreed maximum demand price is used to calculate the non-locational and common service components of prescribed TUOS services, the one that results in the lower estimated charge will apply[23]; and
- a very small number of prudent discounts will be in place over the 2023-27 regulatory period[24].

These amendments are reflected in Section 6.9.3 and Section 9 of our Proposed Pricing Methodology.

Timeframe for publication of the Modified Load Export Charge (MLEC)

Prior to the Distribution Network Pricing Arrangements Rule[25] we were required to publish the MLEC by 15 March each year. The Rule revised this timeframe to 15 February from January 2017 onwards. For clarity, we have amended the publication date to the February timeframe in the Rules[26].

This amendment is reflected in Appendix D of our Proposed Pricing Methodology.

16.4 Summary

Powerlink considers that its Proposed Pricing Methodology meets all compliance requirements given that it includes all relevant information prescribed under the Rules and AER's Pricing Methodology Guidelines 2014. Our Proposed Pricing Methodology for the 2023-27 regulatory period has been informed by our Transmission Pricing Consultation.

22 Pricing Methodology Guidelines, AER, 2014, clause 2.3(c)(7)(B).
23 Pricing Methodology Guidelines, AER, 2014, clause 2.3(c)(6).
24 Pricing Methodology Guidelines, AER, 2014, clause 2.1(k).
25 National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, (November 2020).
26 National Electricity Rules, clause 6A.24.2(b).

17. Demand Management Innovation Allowance Mechanism

17.1 Introduction

The objective of the Demand Management Innovation Allowance Mechanism (DMIAM) is to provide Transmission Network Service Providers (TNSPs) with funding for research and development in demand management projects that have the potential to reduce long-term network costs[1].

This chapter sets out our assessment of the likely application of the DMIAM during the 2023-27 regulatory period. This assessment is based on the reasoning provided by the Australian Energy Market Commission (AEMC) in its Final Rule Determination[2] and the Australian Energy Regulator's (AER's) Draft DMIAM[3].

The DMIAM is expected to be finalised by the AER in June 2021. We will provide updated information on our approach to the DMIAM in our Revised Revenue Proposal, which will be due around December 2021.

17.2 Regulatory requirements

The National Electricity Rules (the Rules)[4] require the AER to develop a DMIAM for TNSPs. In developing the DMIAM, the Rules require the AER to take account of a number of matters[5], in particular:

- demand management projects should have the potential to manage ongoing changes in demand;
- projects should be innovative and not otherwise be efficient and prudent non-network options; and
- the allowance should only provide funding that is not available from any other source, including under a revenue determination.

The AER released its Draft DMIAM and Explanatory Statement in December 2020, which commenced formal consultation on the proposed DMIAM. Prior to this the AER released an Issues Paper which sought preliminary views from stakeholders. The AER intends to publish its Final DMIAM and Explanatory Statement in June 2021. In developing our Revenue Proposal, we have given consideration to the information in the Draft DMIAM and Explanatory Statement to inform how the DMIAM should apply.

17.3 Application of the DMIAM to our 2023-27 regulatory period

In its Final Determination that introduced the DMIAM, the AEMC specifically discussed the question of transitional arrangements for Powerlink, given the likely timing of finalisation of the DMIAM. The AEMC concluded that Powerlink could highlight its intention to propose application of the DMIAM in its Revenue Proposal and then provide the formal requirements under the scheme in its Revised Revenue Proposal. The AEMC sought the AER's feedback on this arrangement. The AER confirmed it will allow Powerlink to follow this approach.

Our request to the AER to amend or replace the Framework and Approach (F&A) paper for our 2023-27 revenue determination process included that the DMIAM should apply to Powerlink. In its Final F&A paper the AER stated its intention to apply the DMIAM to Powerlink for the 2023-27 regulatory period. The AER also noted, given the expected timing for the finalisation of the transmission DMIAM, that we will have an opportunity to fully reflect the finalised DMIAM in our Revised Revenue Proposal, to be submitted in December 2021.

17.4 Our approach

While still not finalised, the Draft DMIAM sets out the AER's proposal for the structure and parameters of the DMIAM. Based on these initial views our approach to the DMIAM consists of:

- an ex-ante allowance of $200,000 (real, 2020/21) + 0.1% of Maximum Allowed Revenue (MAR), or $3.5m for the 2023-27 regulatory period;
- the allowance is for operating expenditure only; and
- we will consider projects that improve wholesale market outcomes as well as those that help meet our mandated reliability of supply standards.

1 National Electricity Rules, clause 6A.7.6(b).
2 Demand Management Incentive Scheme and Innovation Allowance for TNSPs, Rule determination, Australian Energy Market Commission, December 2019.
3 Draft Demand Management Innovation Allowance Mechanism – Electricity transmission network service providers, Australian Energy Regulator, December 2020.
4 National Electricity Rules, clause 6A.7.6.
5 National Electricity Rules, clause 6A.7.6(c).

As the DMIAM is not yet finalised we have not included any forecast for it in our Revenue Proposal. After the DMIAM is finalised in June 2021 our Revised Revenue Proposal will include an appropriate provision.

The scale of electricity transmission infrastructure and the large quantities of energy being transported across the transmission network can mean there are fewer opportunities for demand management to provide a suitable alternative to network investment.

Given the likely size of the allowance we intend to focus our efforts on a limited number of potential opportunities where we can envisage end-consumer demand management being directly applicable to transmission level outcomes. We can also see advantages in the DMIAM being structured so that multiple Network Service Providers (NSPs) can collaborate and pool funding to progress projects across network ownership boundaries. Ideally this would include both transmission and distribution businesses. Our initial thinking is to explore how we might be able to harness demand management capability so as to extend existing transmission network limits sometime in the future.

While we recognise the potential for demand management initiatives to reduce long-term network costs by promoting innovative thinking, we want to ensure that such initiatives are not already captured or better catered for under our operating expenditure or other relevant incentive schemes.

17.4.1 Potential demand management projects

While we have not developed any firm proposals at this time, some conceptual demand management projects that we may explore further include:

- extension of an existing System Integrity Protection Scheme (SIPS) that currently trips generation and/or load to also trigger a response such as a mode change on a Battery Energy Storage System (BESS). As a Research and Development project, the BESS could be relatively small and does not need to be optimally located. The objective is to prove the technical capability to be integrated into a SIPS;
- tests of the ability to provide a co ordinated demand response that includes both fast response, such as a BESS, and slower response, such as embedded generation or load reduction; and
- collaborate with interconnected Transmission Network Service Providers (TNSPs) or Distribution Network Service Providers (DNSPs) to establish protocols for sharing demand management resources and high speed signalling for activation of those resources across network boundaries.

17.5 Summary

The DMIAM is not expected to be finalised by the AER until June 2021, after which we will consider the detailed operation of the mechanism. We seek to have the DMIAM apply to us during the 2023-27 regulatory period and we will provide additional information to the AER as part of our Revised Revenue Proposal.

Attachment I Key Inputs and Assumptions

The following tables provide a brief guide and reference to the key inputs and assumptions upon which our forecasts for the operating expenditure, capital expenditure and financial elements of our Revenue Proposal are based. This is a brief guide only and detailed information should be sourced from the relevant chapters of this Revenue Proposal.

Operating expenditure

Element	Inputs and assumptions
Base-step-trend	
Efficient base year	2018/19 audited accounts. Independent review of the efficiency of Powerlink's base year operating expenditure – HoustonKemp.
Step changes	No step changes proposed.
Trend – output growth	Australian Energy Market Operator (AEMO) 2020 Electricity Statement of Opportunities (ESOO) Central Scenario. AEMO 2020 Final Integrated System Plan (ISP). Powerlink Economic Benchmarking Regulatory Information Notice (EB RIN) data for 2019/20. AER's 2020 TNSP Annual Benchmarking Report data.
Trend – price growth	Labour (internal) – simple average of WPI forecasts provided by BIS Oxford Economics (Energy, Gas, Water and Waste Services (EGWWS) – Queensland) and DAE (National Utilities WPI forecast). Superannuation Guarantee increase of 0.5% has been added for relevant years 2021/22 to 2025/26. Material cost inputs – inflation forecast (2.25%).
Trend – productivity	Based on a top-down productivity assessment and consideration of the AER's industry average benchmark productivity (0.3% p.a.), as per the AER's Annual Benchmarking Report for TNSPs (December 2020).
Category specific forecasts	
Debt raising	8.46 basis points per annum, based on independent advice from Incenta.
AEMC Levy	Forecasts confirmed by the Department of Energy and Public Works (DEPW).

Capital expenditure

Element	Inputs and assumptions
General	
Asset Strategy & Information	Approved asset management documents, SAP data systems.
Price growth	Labour (internal) – simple average of WPI forecasts provided by BIS Oxford Economics (Energy, Gas, Water and Waste Services (EGWWS) – Queensland) and DAE (National Utilities WPI forecast). Labour (external) – simple average of WPI forecasts provided by BIS Oxford Economics (Construction – Queensland) and DAE (National All Industries WPI forecast). Superannuation Guarantee increase of 0.5% has been added for relevant years 2021/22 to 2025/26. Material cost inputs – inflation forecast (2.25%).
Estimated unit rates	Derived from Powerlink's standard network project estimating practices. Independent benchmarking of unit rates by GHD.
Load driven (augmentation, easements, connections)	
Demand, energy and generation forecast	AEMO 2020 ESOO Central Scenario and AEMO's 2020 Final ISP.
Contingent projects	Potential developments identified in Powerlink's 2020 TAPR above the ESOO Central Scenario demand forecast.
Non-load driven (reinvestment, security/compliance/other)	
Repex model (reinvestment)	Application of Powerlink's calibrated version of the AER's Repex Model. Inputs reflect current Asset Management Plans. Replacement quantities calibrated to recent historical actuals for 2015-2020.
'Bottom up' (reinvestment, system services)	More than 70% of total capex forecast. Based on current Asset Management Plans and systems information which have been separately scoped and estimated.
Trend model (security, compliance, other)	Historical trend applied (2011-2020), adjusted for one-off needs.
Non-network	
IT, buildings, vehicles	Based on current Powerlink strategies and development plans.
Tools	Historical trend applied (2011-2020), adjusted for one-off needs.

Rate of Return, Taxation, Regulatory Asset Base and Inflation

Element	Inputs and assumptions
Rate of Return	4.44% nominal vanilla Weighted Average Cost of Capital (WACC). Cost of debt is based on an estimate of the AER's trailing average approach and assumes Powerlink's 2020/21 interest rate remains unchanged for the 2023-27 regulatory period. Cost of equity is based on a risk free rate of 0.82%.
Taxation	Estimate of immediately deductible capex has been included based on historical Powerlink data. All new assets are depreciated using the diminishing value method for tax purposes, with the exception of buildings and in-house software.
Regulatory Asset Base	Forecast asset disposals of $3.6m for motor vehicles and $11m for the proposed sale of premises as part of our Future Workplace Options Analysis. Net transfer of assets out of the RAB of $2.4m.
Inflation	2.25% based on the AER's inflation forecast methodology.

Glossary

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
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
CCP23	AER's Consumer Challenge Panel, sub-panel 23
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
DEPW	Department of Energy and Public Works
DER	Distributed Energy Resources
DI	Dispatch Interval
DMIAM	Demand Management Innovation 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
EGWWS	Electricity, Gas, Water and Waste Services
EMS	Energy Management System
ENA	Energy Networks Australia
ERP	Enterprise Resource Planning
ESB	Energy Security Board
ESOO	AEMO's Electricity Statement of Opportunities
EUAA	Energy Users Association of Australia

EV	Electric Vehicle
F&A	Framework and Approach
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	AEMO's Integrated System Plan
IT	Information Technology
ITAA	Income Tax Assessment Act 1997
IVAMS	In-Vehicle Asset Management System
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
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
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
REZs	Renewable Energy Zones
RFM	Roll Forward Model
RIN	Regulatory Information Notice
RIT-T	Regulatory Investment Test for Transmission
RoR	Rate of Return
RPRG	Powerlink's 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. Appendices can be accessed via the AER's website for Powerlink's revenue determination under the Proposal tab.

1.01	Board Certification of Key Inputs and Assumptions
1.02	Statutory Declaration on Powerlink's Reset RIN Return
1.03	NER Compliance Checklist
1.04	RIN Compliance Checklist
1.05	Document Register
2.01	Business Narrative
3.01	Engagement Plan
3.02	Submissions on our draft Revenue Proposal
3.03	Customer Panel Statement on Engagement
3.04	Terms of Reference for the Revenue Proposal Reference Group
3.05	Customer Panel Evaluation Survey
3.06	2020 Stakeholder Perception Survey Summary
3.07	Transmission Network Forum Participant Feedback Summary 2020
4.01	HoustonKemp – Efficiency of Powerlink's Base Year Operating Expenditure Report
5.01	Operating and Capital Expenditure Criteria and Factors
5.02	2020 Transmission Annual Planning Report
5.03	Expenditure Forecasting Methodology
5.04	Non Load-Driven Network Capex Forecasting Methodology
5.05	IT Plan 2023-27
5.06	Guide to Non-Network Capital Expenditure
5.07	Contingent Projects
6.01	Forecast Operating Expenditure Methodology and Model
6.02	Operating Expenditure Productivity Approach and Potential Initiatives
6.03	Operating Expenditure Step Changes Approach
6.04	Marsh – Insurance Projections
6.05	Incenta – Benchmark Debt and Equity Raising Costs Report
7.01	BISOE – Labour Cost Escalation Forecasts to FY2027 Report
7.02	GHD – Unit Rates for Repex Modelling Report
7.03	Cost Estimating Methodology
8.01	Regulatory Asset Base Transfers - confidential
9.01	Nominated Averaging Periods - confidential
10.01	Depreciation Tracking Approach
12.01	Marsh – Nominated Pass Through Events
15.01	Setting STPIS Values
15.02	Energy Networks Australia - STPIS Review Letter

15.03	WSP – Statistical Methodology for STPIS SC Validation Report
16.01	Proposed Pricing Methodology
16.02	Transmission Pricing Consultation Paper
16.03	Transmission Pricing Consultation Draft Positions Paper
16.04	Transmission Pricing Consultation Final Positions Paper
16.05	Submissions to Powerlink's Transmission Pricing Consultation Paper

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 Model
Capital Expenditure Sharing Scheme (CESS) Model
Depreciation Tracking Module
Efficiency Benefit Sharing Scheme (EBSS) Model
Operating Expenditure Model
Post-Tax Revenue Model (PTRM)
Rate of Return Model
Repex Model – Calibration Model
Repex Model – Forecast Model
Roll Forward Model (RFM)
Trend Forecast Model

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