



Jemena Electricity Networks (Vic) Ltd

2021-26 Electricity Distribution Price Review Regulatory Proposal

Attachment 06-01

Standard Control Services - Operating Expenditure



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Appendix A Compliance with the NER
Appendix B Feedback on our draft plan
Appendix C Overview of operating expenditure categories

Glossary

Current regulatory period	The regulatory control period covering 1 January 2016 to 31 December 2020
Draft plan	On 31 January 2019, we released our draft plan which outlined the feedback we received from our customers, our proposed expenditure and how our plans met our customer expectations
Intervening period	The six months between the current regulatory period and the next regulatory period (1 January 2021 to 30 June 2021)
Next regulatory period	The regulatory control period covering 1 July 2021 to 30 June 2026
Regulatory Proposal	Our proposal for the setting of regulated revenues over the Next regulatory period
RIN response	Our response to information sought by the AER in the Regulatory Information Notice served on 4 Oct 2019

Abbreviations

A&O	Administration and overheads
ABS	Australian Bureau of Statistics
ACS	Alternative Control Services
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BISOE, BIS	BIS Oxford Economics
bppa	Basis Points Per Annum
CALD	Culturally and Linguistically Diverse
CAM	Cost Allocation Methodology
CCP	Customer Challenge Panel
CEG	Competition Economists Group
CY	Calendar Year
DAE	Deloitte Access Economics
DNSP	Distribution Network Service Provider
DRC	Debt Raising Costs
ECA	Energy Consumers Australia
EBSS	Efficiency Benefit Sharing Scheme
EDPR	Electricity Distribution Price Review
EI	Economic Insights
ESC	Essential Services Commission of Victoria
ESV	Energy Safe Victoria
EWON	Energy and Water Ombudsman NSW
FGLS	Feasible Generalised Least Squares
FTE	Full Time Equivalent
FY	Financial Year
GIS	Geographical Information System
GSL	Guaranteed Service Level
JEN	Jemena Electricity Networks (Vic) Ltd
JGN	Jemena Gas Networks (NSW) Ltd
MPFP	Multilateral Partial Factor productivity
MTFP	Multilateral Total Factor Productivity
NER	National Electricity Rules
O&M	Operating & Maintenance
OEF	Operating Environment Factors
OH&S	Occupational Health and Safety
PIAC	Public Interest Advisory Centre
PPI	Partial Performance Indicators
PTRM	Post Tax Revenue Model

RAB	Regulatory Asset Base
RIN	Regulatory Information Notice
RY	Regulatory Year
SCS	Standard Control Services
SFA	Stochastic Frontier Analysis
SGSPAA	SGSP (Australia) Assets Pty Ltd
STPIS	Service Target Performance Incentive Scheme
WPI	Wage Price Index

Overview

The purpose of this document is to provide information on our historical operating expenditure outcomes and forecast operating expenditure requirements, including an explanation of how we have developed our operating expenditure forecasts for standard control services (**SCS**) for the regulatory control period covering 1 July 2021 to 30 June 2026 (**next regulatory period**). It also explains how the feedback that we have received from our customers has informed the development of our operating expenditure forecast. It seeks to demonstrate that the operating expenditure forecasts are prudent, efficient and compliant with the relevant provisions of the National Electricity Rules (**NER**) (see Appendix A).

The document is structured as follows:

- This overview summarises Jemena Electricity Networks (Vic) Ltd (**JEN's**) operating expenditure forecasts for the next regulatory period, and the key changes to our forecasts since we published our draft plan for public consultation on 31 January 2019 (**draft plan**). It covers what we have heard from our customers, and how we have incorporated this into our plans. The feedback received from stakeholders relevant to our operating expenditure on our draft plan is included in Appendix B.
- Section 1 describes JEN's operating cost categories
- Section 2 provides an overview of our current period operating expenditure outcomes
- Section 3 details our operating expenditure forecasting approach
- Section 4 explains and justifies our base year operating expenditures, including our benchmarking performance
- Section 5 describes our method for trending the base year
- Section 6 discusses step changes (which are further detailed in Attachment 06-05 *Operating expenditure step changes*)
- Section 7 explains and justifies the other elements of our operating expenditure forecast that we have prepared using specific (or bottom-up) forecasting approaches
- Section 8 presents and describes JEN's operating expenditure forecast.

Unless otherwise stated, all financial numbers in this document are presented in real June 2021 dollars (i.e. dollars as at 30 June 2021).

Our engagement with our customers

A key part of our process in developing our 2021-26 regulatory proposal (**regulatory proposal**) was to engage with our customers and ask them about their preferences in relation to our services (including our prices), now and into the future. Throughout our customer engagement program, we heard that affordability is a crucial issue across all of our customer groups, and they want us to help put downward pressure on electricity prices to help reduce the cost of living and doing business.

Recognising that affordability is a crucial issue for our customers, we are committed to delivering several initiatives which are aimed at reducing costs, both now and into the future. These initiatives include implementing a transformation program to reduce our operating expenditure and a commitment to deliver ongoing productivity improvements.




Our customers also told us that they value and expect a safe and reliable electricity supply. Although they said that they are satisfied with the current levels of reliability, they require the network to support more two-way power flows from distributed energy resources, meet the growing needs from the electrification of the transport sector, and smart homes and internet-based businesses that rely on electricity being available for their online needs.

Improved affordability, therefore, cannot come at the cost of service performance—the right balance is needed. Therefore, our operating expenditure forecasts have been developed to ensure that we can continue to provide our customers with the level of reliability they expect at an efficient cost.

Feedback from our People's Panel

Our People's Panel gave us specific feedback on the activities they thought we should focus on in the next regulatory period. We summarise the recommendations that are relevant to operating expenditure in Figure OV–1 below and explain how these recommendations have been captured in our operating expenditure proposal.

Figure OV–1: People's Panel recommendations and their linkage to operating expenditure

Recommendation from our People's Panel	Relationship to operating expenditure
<p>4</p>  <p>Enable increased feed-in of solar (and other renewables) into the grid, by improving the performance of the grid through new technologies.</p>	<p>A key feature of our regulatory proposal is our Future Grid program.¹ In the program, we outline the activities we plan to undertake, which encompass a range of network and non-network capital expenditures as well as operating expenditure. Our program includes several “Enabling DER” activities, which will build a foundation for the network to support increased two-way flows and energy trading by customers in future by enabling greater feed-in of solar and other renewables.</p> <p>In section 6 of this attachment, we outline a step change in operating expenditure necessary to implement and operationalise our Future Grid program.</p>
<p>7</p>  <p>Maintain the number of outages as they are today – on average each customer experiences four outages every four years.</p> <p>8</p>  <p>Maintain the length of outages as they are today – on average 51 minutes per outage.</p>	<p>Our panel members told us the frequency and duration of outages across the network should be maintained. To ensure we achieve this goal, we have forecast operating expenditure that allows us to undertake maintenance and operating activities—such as managing the control room, sending crews in response to outages and emergencies or managing vegetation clearances—that will enable us to continue providing the same level of service reliability.</p>

Our forecast operating expenditure

Operating expenditure is a critical component of our building block costs, accounting for approximately 45% of JEN's total cost of service over the next regulatory period. Table OV–1 details our forecast operating expenditure over the next regulatory period. We include the forecast operating expenditure model as Attachment 06-04.

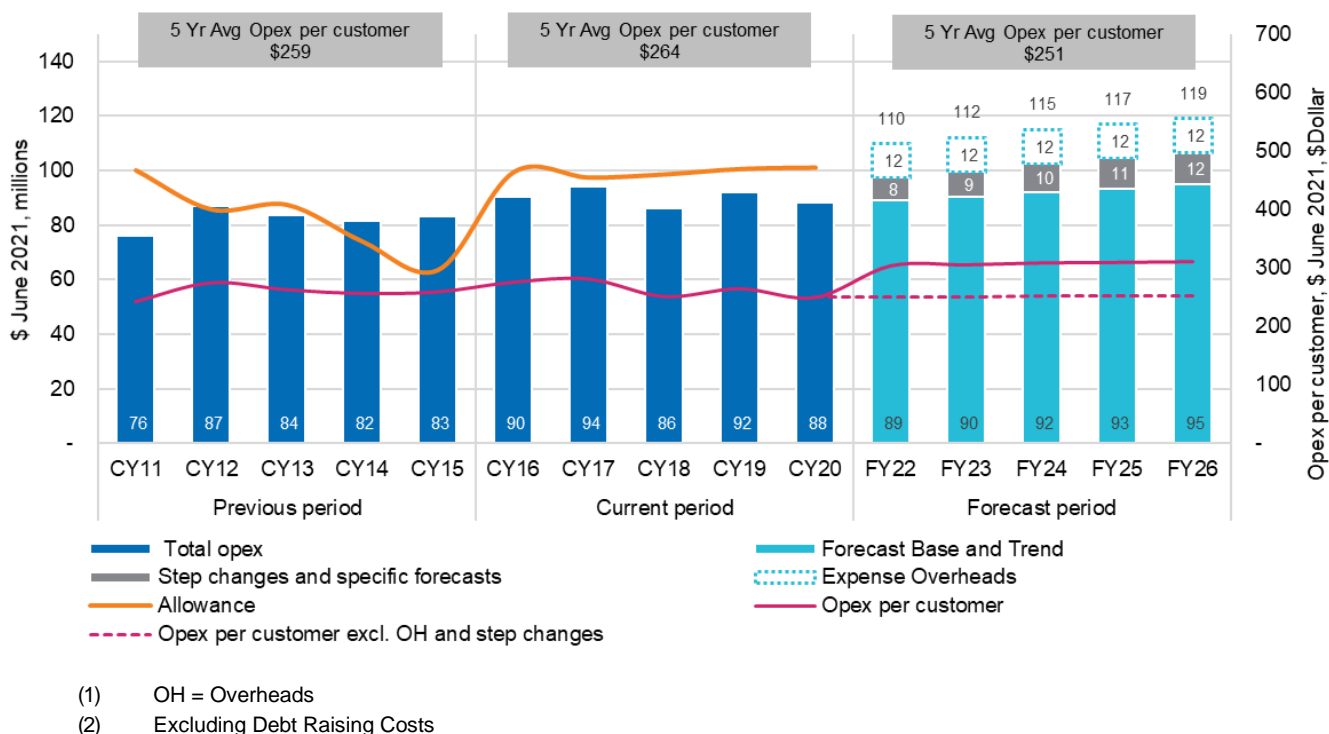
Table OV–1: Operating expenditure forecast, including debt raising costs (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Total Operating expenditure	110.5	112.8	115.7	117.7	119.8	576.6

¹ See Attachment 05-04 *Future grid investment proposal*.

Although our total operating expenditure will increase over the next regulatory period, we expect that our operating expenditure per customer will remain in line with that in the regulatory control period covering 1 January 2016 to 31 December 2020 (**current regulatory period**)² (see Figure OV–2).

Figure OV–2: Historical and forecast operating expenditure 2010-11 to 2024-25 (\$June 2021, millions)



In Figure OV–2, we show a comparison of operating expenditure per customer over the previous, current and next regulatory periods (as shown in the right-hand axis). We also show the operating expenditure per customer both with and without the expensing of corporate overheads, step changes and specific forecasts. Although our operating expenditure per customer increases over the next regulatory period, this is primarily driven by:

- a change in our accounting treatment to expense all corporate overheads in the next regulatory period consistent with our Cost Allocation Methodology (**CAM**) which was approved by the Australian Energy Regulator (**AER**) in May 2019 (discussed in section 4.5.2 below)
- step changes which arise due to either external factors such as new regulatory obligations, legislative impacts, market movements or internal factors such as efficient trade-offs between capital expenditure and operating expenditure that are not captured in our efficient base year or trend escalation (discussed in section 6 below).

When we remove these factors to compare our current and forecast period, on a like-for-like basis, the operating expenditure per customer reduces from an average of \$264 per year over the current period to \$251 over the next period. This means that we are forecasting to provide the same level of service with \$13 less operating expenditure per customer in the next period. Apart from the reduction in operating expenditure per customer, the cost of maintaining our growing network also reduces. Despite a 20 per cent increase in circuit length that JEN needs to maintain, the operating expenditure per km of circuit length reduces by \$1,059—from an average of \$13,782 in the current period to \$12,723 in the next regulatory period.

² The operating expenditure for the six-month period between the current regulatory period and the next regulatory period (**intervening period**), is outlined in our separate submission; JEN, *Regulatory Proposal for the intervening period*, 31 January 2020.

Comparing our performance between the base year operating expenditure of the current period (calendar year (CY) 2014) and the next period (CY18), our improvement in operating expenditure efficiency can be measured by the operating expenditure Multilateral Partial Factor Productivity (MPFP) index. JEN's operating expenditure MPFP index has improved from 0.946 to 0.971, indicating a 2.6 per cent efficiency improvement between the two base years. When the output weights in the operating expenditure MPFP index are substituted with JEN specific weights³ instead of the industry average weights, the operating expenditure MPFP improved from 1.056 in CY14 to 1.107 in CY18, which is a 4.9 per cent efficiency improvement.

Our forecast operating expenditure for the next regulatory period represents an efficient level of expenditure required to deliver the safe, reliable and cost-effective services that our customers have told us they want. It will enable us to continue to:

- provide safe, reliable and cost-effective services through investment in maintenance programs that manage risk and meet customer service requirements
- respond to emergencies so that we minimise supply disruptions
- operate our call centres and other customer service touchpoints
- manage JEN as a regulated business, to meet our legal and regulatory obligations.

We believe that our operating expenditure forecasts reflect the costs of a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering distribution services. In particular, we note that our operating expenditure forecast:

- is based on the AER's preferred base, step and trend approach
- is based on CY18 as base-year which had the lowest operating expenditure in the current regulatory period and was operating under the AER's Efficiency Benefit Sharing Scheme (EBSS) which provided strong incentives to minimise our operating expenditure
- adopts AER's decision on estimated target operating expenditure productivity per annum.⁴

Changes since our draft plan

In our draft plan, our forecast operating expenditure was \$497M over the next regulatory period with a base year CY19 operating expenditure estimate of \$79M, and transformation costs estimate of \$20M. The draft plan operating expenditure forecasts were \$80M lower than our proposed operating expenditure forecasts over the 5 years in the next regulatory period. This change is a result of the following changes we have made since we published our draft plan:

- **Updated base-year operating expenditure based on actuals.** The updated estimate of \$86M⁵ reflects more up to date information on our actual operating expenditure in CY18. Our draft plan was based on a full-year forecast for CY19. We have now decided to use CY18 as the base year because our CY19 operating expenditure includes \$10M of transformation costs. These costs are not representative of ongoing expenses. CY18 also has the lowest actual operating expenditure over the years CY16 to CY19.

³ In Economic Insights' MPFP analysis, output weights are estimated for each individual DNSPs using Leontief cost function. These weights are then averaged to derive a set of industry average weights to be applied to the MPFP indices. The improvement in operating expenditure efficiency calculated using operating expenditure MPFP indices can be based on either the industry average weights or DNSP-specific weights.

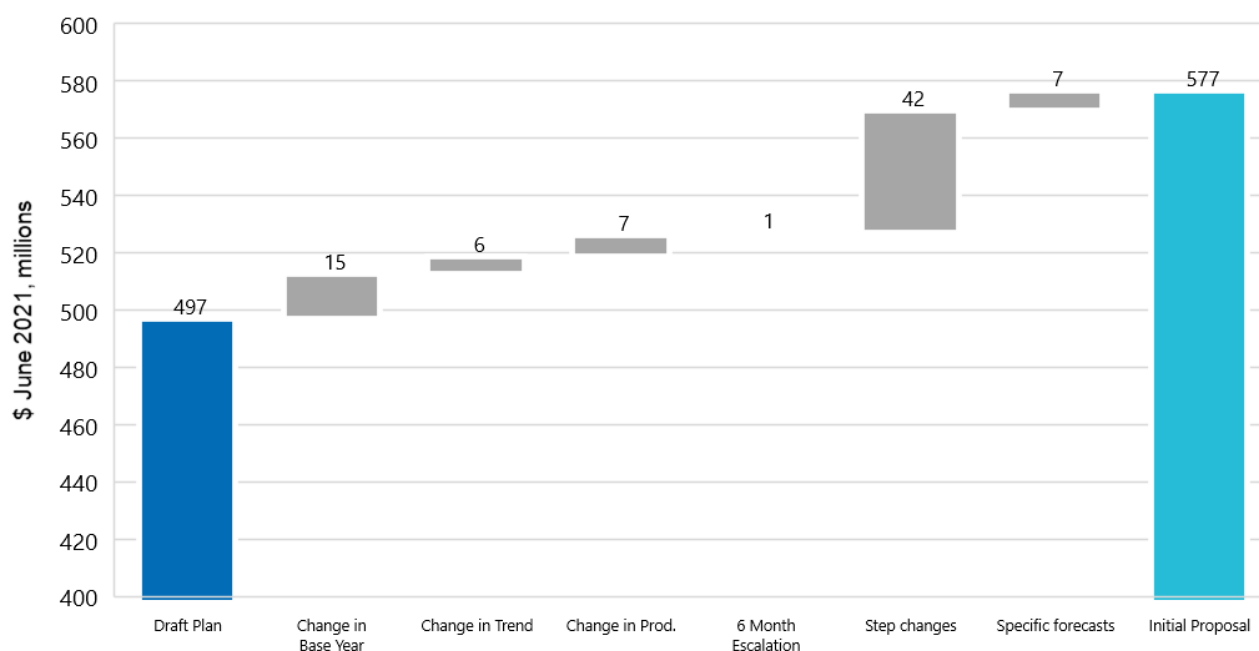
⁴ AER, *Final decision paper: Forecasting productivity growth for electricity distributors*, 8 March 2019.

⁵ \$82M in nominal dollars and \$86M in real June 2021 dollars.

- **An updated trend escalation forecast.** The draft plan operating expenditure forecasts were based on the AER's preferred approach of using the average of BIS Oxford Economics (**BISOE**) and Deloitte Access Economics (**DAE**) wage-price Index (**WPI**) measures for input escalation and econometric output variables for output growth escalation (customer numbers, circuit length, ratcheted maximum demand and energy delivered). While the AER has changed its approach in recent draft decisions; we continue to apply the same approach to the CY18 base year. The application of this approach to a different operating expenditure base (CY18 instead of CY19) results in changes (see section 5).
- **An updated productivity target of 0.5 per cent.** This target has also been applied based on the AER's final decision on productivity review instead of the placeholder 1 per cent we used in our draft plan, which was based on the AER's *Forecasting productivity growth for electricity distributors draft decision* (see section 5.4).
- **A six-month deferral of the start of the next regulatory period.** In April 2019, the Victorian Minister for Energy, Environment and Climate Change advised JEN of her intention to make changes to the timing of Victorian electricity network regulatory years. Changes to the *National Electricity (Victoria) Act 2005* (Vic) will change our regulatory years from calendar year to financial year (ending 30 June). This change means that we must take into account an additional six month period of real input escalation and network growth for the once-off transition from calendar to financial years. This change equates to a \$1M increase in operating expenditure. We are also seeking an additional \$0.5M for additional regulatory reporting that comes about from this change (see section 6).
- **Addition of step changes.** Higher public liability insurance premiums and changes in regulatory obligations—including the change in the regulatory period noted above—are expected to add \$42M to the operating expenditure forecasts (see section 6).⁶
- **An update of the specific forecasts.** Updated debt raising costs based on expert advice from Competition Economist Group (**CEG**) (see section 7.3). An additional specific forecast of the Energy Safe Victoria (**ESV**) levy (see section 7.2).

Figure OV–3 summarises the impact of each of the changes to our draft plan on the total operating expenditure over the next regulatory period, which forms part of our regulatory proposal.

Figure OV–3: Key changes from our draft plan to this regulatory proposal (\$ June 2021, millions)



⁶ These are based on market changes and new obligations that have become known (or clearer) since the draft plan was released.

List of operating expenditure attachments

To support this operating expenditure proposal outlined in this document, we rely on several supporting materials; we list these in Table OV–2.

Table OV–2: List of operating expenditure attachments

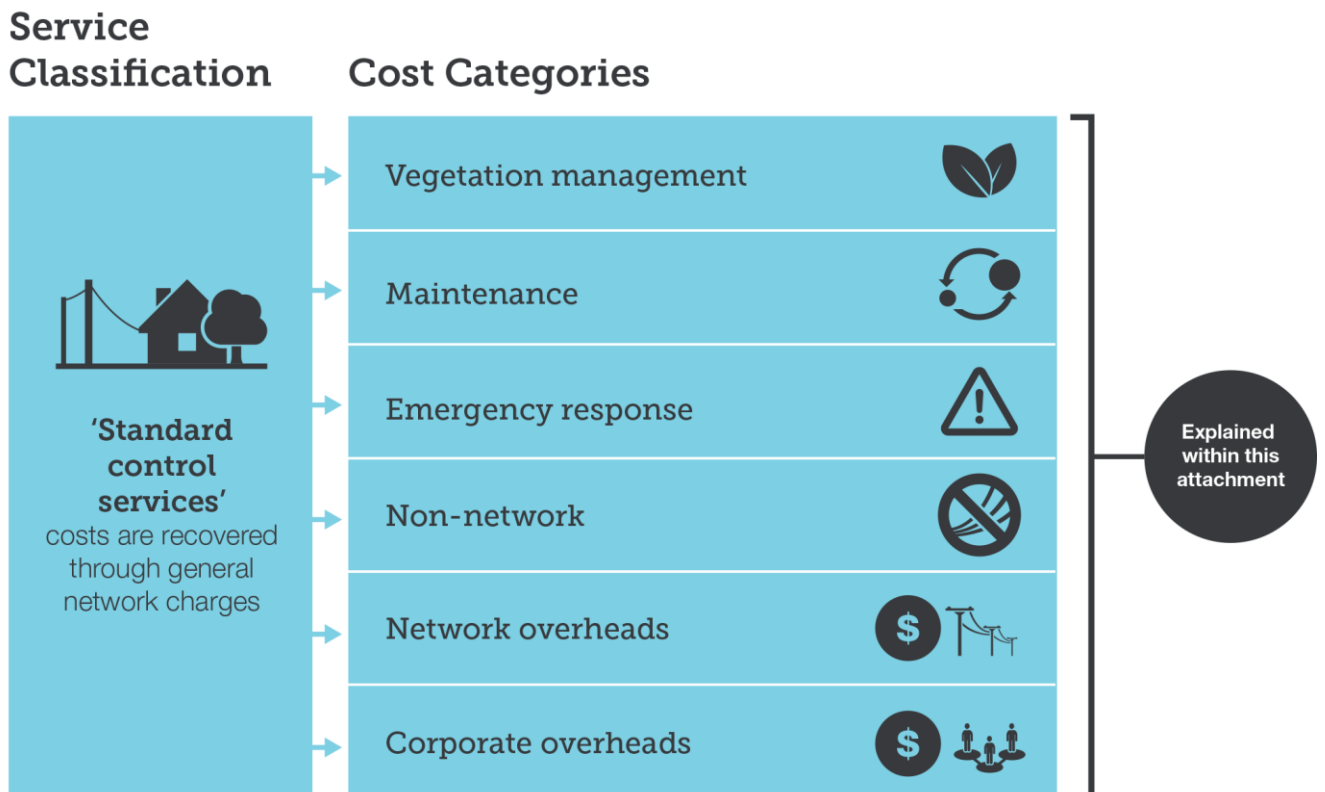
Attachment	Name	Author
02-01	Our customer, stakeholder and community engagement	JEN
06-01	Operating expenditure (historical and forecast; this document)	JEN
06-02	Expert opinion on real price escalation	Frontier Economics
06-03	The cost of arranging debt issues	CEG
06-04	SCS operating expenditure model for the next regulatory period	JEN
06-05	Operating expenditure step changes	JEN
06-06	Insurance premium forecast report	AON
06-07	SCS operating expenditure model for the intervening period	JEN
05-07	Real labour rate escalation	BISOE

1. Operating cost categories and cost allocation

1.1 Operating cost categories

We incur operating expenditure on the maintenance of the network, vegetation management on and around our electricity distribution network, design and planning of the network, responding to emergencies, providing training, safety and corporate support. Our operating costs are split into six high-level categories. A breakdown of these operating cost categories is shown in Figure 1–1.⁷

Figure 1–1: Operating expenditure by cost category



Note: Appendix C includes an overview of each of the operating expenditure cost categories.⁸

1.2 Cost allocation

The JEN CAM that has been approved by the AER⁹ and is to apply during the next regulatory period¹⁰ governs how costs are allocated across services within JEN. It includes the allocation of the expenses between SCS and Alternative Control Services (**ACS**), Negotiated Services and unregulated services, in accordance with clause 6.15.4 of the NER. The CAM has been applied to ensure that remove ACS, negotiated and unregulated operating expenditure are not included in our SCS base year operating expenditure amount.

⁷ NER, S6.1.2(1)(ii).

⁸ NER, S6.1.2(1)(iv).

⁹ AER, *Final Decision, Jemena Electricity Networks (Vic) Ltd Revised Cost Allocation*, May 2019.

¹⁰ JEN, *Cost Allocation Methodology*, 29 March, 2019.

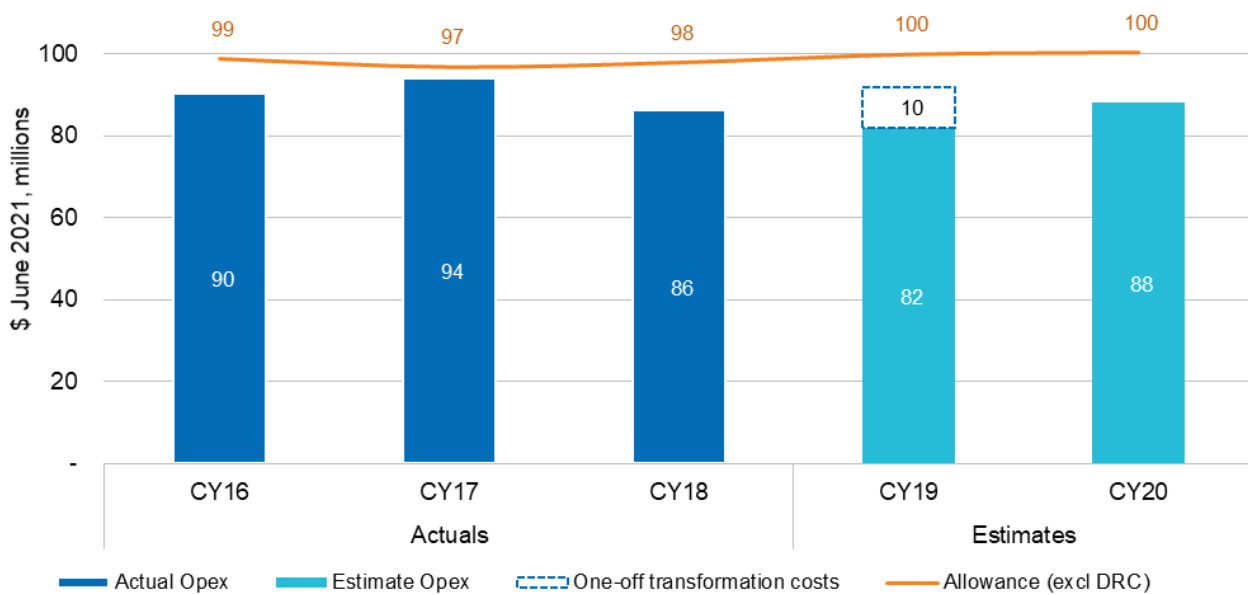
2. Overview of current period performance

For the current regulatory period, the AER determined JEN's CY14 operating expenditure as an efficient base year to be used in forecasting the current regulatory period allowance and subsequently approved an efficient operating expenditure allowance of \$498M.

Over the current regulatory period, we expect to incur \$451M of operating expenditure, which is \$43M less than the efficient allowance of \$494M (excluding debt raising costs). This reduction arises despite the additional costs of our transformation program incurred in CY19 and emerging regulatory obligations,¹¹ which did not form part of the operating expenditure allowance for the current regulatory period.

The below Figure 2–1 shows how we performed against our allowance each year during the current regulatory period.

Figure 2–1: Operating expenditure versus allowance during the current regulatory period (\$ June 2021, millions)



(1) DRC = Debt raising costs

When the AER determined our operating expenditure allowance in 2016 for the current regulatory period, we were deemed to be efficient, and we have operated—or will operate—within that efficient allowance every year.

2.1 Operating expenditure by cost category

JEN captures expenditure at a cost category level as shown in Figure 1–1. Further information on the types of costs incurred by category is outlined in Appendix C.

Figure 2–2 and

Table 2–1 provide a breakdown of our operating expenditure in the previous, current and next regulatory periods by cost category, along with the total operating expenditure allowance where applicable.¹²

¹¹ For example, *Electricity Distribution Business ring-fencing* and *5-minute settlement*, to name but a few.

¹² NER, S6.1.2(7).

Figure 2–2: Operating expenditure by cost category (\$ June 2021, millions)

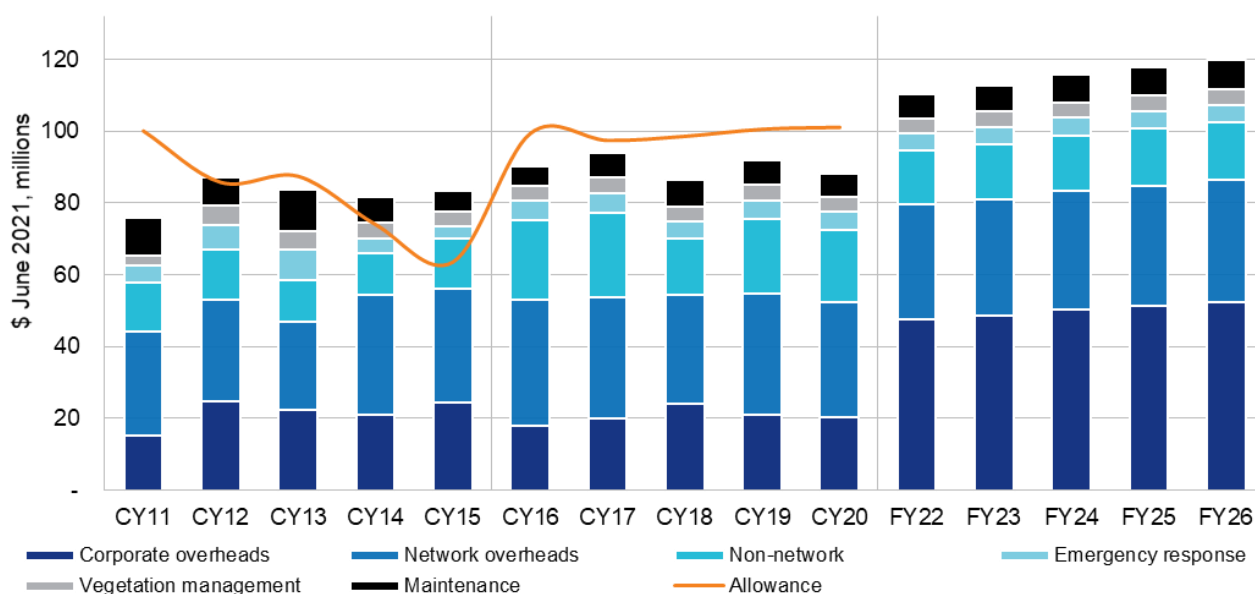


Table 2–1: Operating expenditure by cost category (\$ June 2021, millions)

	Previous Regulatory Period					Current Regulatory Period					Next Regulatory Period ⁽¹⁾				
	CY11	CY12	CY13	CY14	CY15	CY16	CY17	CY18	CY19	CY20	FY22	FY23	FY24	FY25	FY26
Vegetation management	3	5	5	4	4	4	5	4	4	4	4	4	4	4	4
Maintenance	10	8	12	7	6	6	7	7	7	6	7	7	8	8	8
Emergency response	5	7	8	4	4	5	5	5	5	5	5	5	5	5	5
Non-network	14	14	12	12	14	22	24	16	21	20	15	15	16	16	16
Network overheads	29	28	24	33	32	35	34	30	34	32	32	32	33	33	34
Corporate overheads	15	25	23	21	24	18	20	24	21	20	48	49	50	51	52
Total costs	76	87	84	82	83	90	94	86	92	88	111	113	116	118	120

(1) The operating expenditure step changes have been apportioned across the relevant cost categories.

As can be observed from the information above there is an upward variation in the historical operating expenditure (the previous regulatory period and the current regulatory period) and the next regulatory period. The main drivers for this include:¹³

- The approved change in the treatment of corporate overheads (see section 4.5.2)
- Operating expenditure step changes (see section 6).

¹³ NER S6.1.2(8).

3. Overview of our forecasting approach

3.1 Forecasting method

We have developed our operating expenditure forecasts using the AER's preferred forecasting method, the base, step and trend approach.¹⁴ Additionally, we have also used specific year-by-year forecasts and step changes for the operating expenditure cost categories where base year costs are not representative of the costs that we will incur on these categories in the future.

Under this base-step-trend approach, all expenditure included in the base and trend components are recurrent in nature. The expenditure related to step changes and specific forecasts consist of a mixture of recurrent and non-recurrent expenditures. More details on the nature of the step changes and specific forecasts are provided in Attachment 06-05 *Operating expenditure step changes*.

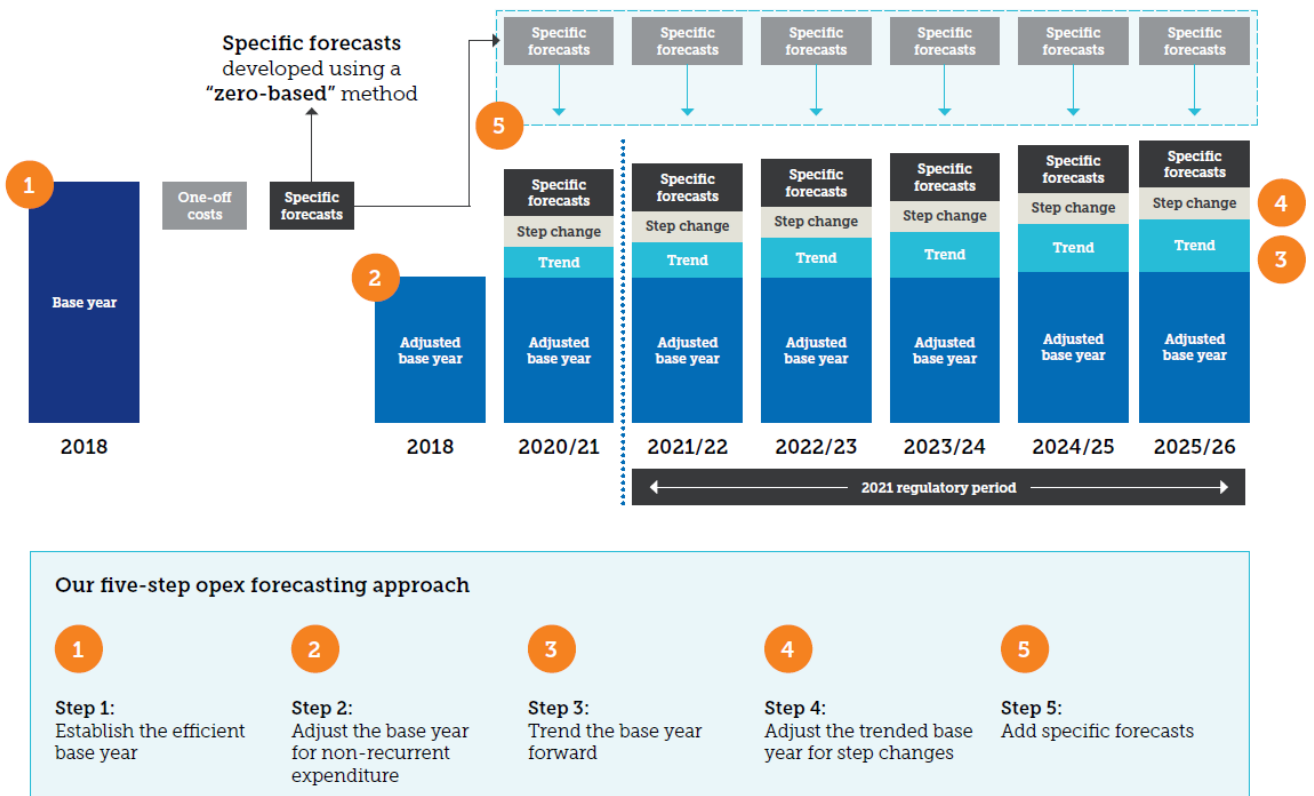
We forecast our operating expenditure by, broadly speaking, undertaking the following five steps:

- **Step one:** we establish an efficient base year, having regard for our current and historical costs. We discuss this step in section 4.
- **Step two:** we adjust this base year for the expensing of corporate overheads to be consistent with our approved CAM. We discuss this in section 4.5.2.
- **Step three:** we trend the base year forward over the next regulatory period, considering expected changes in real labour input costs, network growth and productivity gains. We discuss this in section 5.
- **Step four:** we add in step changes for costs not captured in the base year. We discuss this briefly in section 6 and Attachment 06-05.
- **Step five:** we add in specific forecasts for items where base year costs are not representative of the costs we expect to incur. We have developed specific forecasts for the following items: Guaranteed Service Level (**GSL**) payments, Energy Safe Victoria (**ESV**) distributor levies and debt raising costs (**DRC**). These items are addressed in section 7.

Our approach to forecasting operating expenditure is summarised in Figure 3–1.

¹⁴ This is consistent with our Expenditure Forecasting Methodology 2021-25 regulatory control period submitted to the AER on 20 December 2018.

Figure 3–1: Our operating expenditure forecasting approach



3.2 Key inputs and assumptions underlying JEN's operating expenditure forecast

Sections 4 to 7 describe and substantiate the key inputs and assumptions underlying JEN's operating expenditure forecast, including the basis of the specific forecasts.¹⁵

These sections should be read in conjunction with Attachment 06-04 *SCS opex model*, which is our operating expenditure forecasting model and Attachment 06-05 *Operating expenditure step changes* which provide more details on our proposed step changes.

¹⁵ NER s S6.1.2(3) requires us to set out the forecasts of the key variables we relied on in applying the base, step and trend method to forecast our operating expenditure, as well as the methods and assumptions we used to forecast these variables.

4. Establishing an efficient base year

4.1 Overall

The purpose of the base year in the *base, step and trend* approach is to provide a reasonable starting point for our prudent and efficient operating expenditure forecast. Our base year shows what we currently incur for recurrent activities and reflects our on-going requirements to maintain the quality, safety and reliability of our network during the next regulatory period—consistent with our customers' expectations. Our task is to determine a reasonable approximation of base operating expenditure for the last year of the current period, being CY20, which will not be known at the time of the AER's final decision.

We are proposing a base year determined on a calendar year basis despite moving to financial year-based regulatory years in the next regulatory period, because:

- having a consistent starting point with audited data gives greater confidence around the base level of efficient expenditure rather than transposing our actual reported costs into financial year information
- adopting a CY basis aligns with the operation of the current period EBSS
- the AER has indicated a preference for a CY base year for the Victorian electricity distribution businesses.

The AER's preferred approach is to start with recent actual (or revealed) operating expenditure and adjust it for various factors. Although we will have provided actual and audited CY19 actual operating expenditure to the AER before it makes its final decision, it is affected by the costs of our transformation program and so will not reflect an appropriate level of recurrent expenditure.¹⁶ Given this, we have started with CY18 actual operating expenditure—which we discuss further in sections 4.2, 4.3 and 4.4.

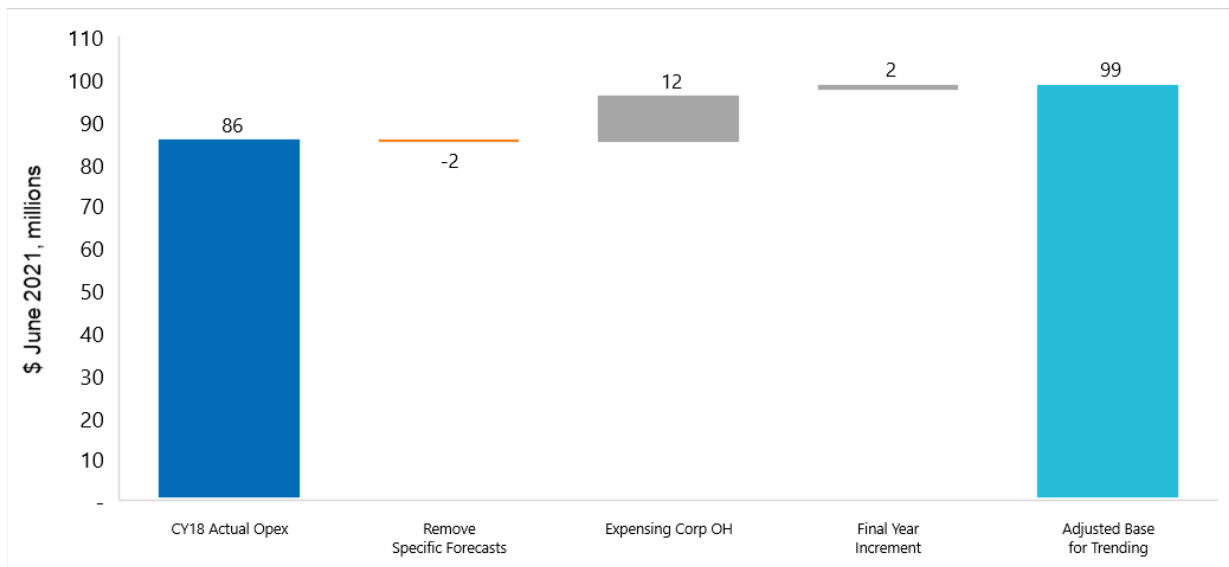
From that starting point, we have adjusted actual CY18 operating expenditure:

- to remove changes in provisions and operating expenditure for categories that are not being forecast using the base, step and trend approach (i.e. DRC, GSL payments and ESV levies)
- for changes to expense all corporate overheads (see section 4.5.2), which are mirrored in our capital expenditure forecasts (see Attachment 05-01 *Forecast capital expenditure*)
- for increments in operating expenditure between CY18 and CY20, being the last year of the current regulatory period (see section 4.5).

The first and last adjustments reflect the AER's standard practice and are included, by default, in its operating expenditure forecast model—which we have used. The second adjustment gives effect to the AER approved changes to our CAM.

Figure 4–1 shows our build-up of the proposed base operating expenditure of \$99M for CY20.

¹⁶ A similar issue existed with our Jemena Gas Networks (JGN) where the AER preferred regulatory year 2018 to be used as base year instead of regulatory year 2019.

Figure 4–1: Our proposed base year operating expenditure (\$ June 2021, millions)

- (1) Corp OH = Corporate overheads
- (2) Any operating expenditure categories not forecast using the base, step and trend approach are removed from the base operating expenditure, consistent with the AER's preferred method.

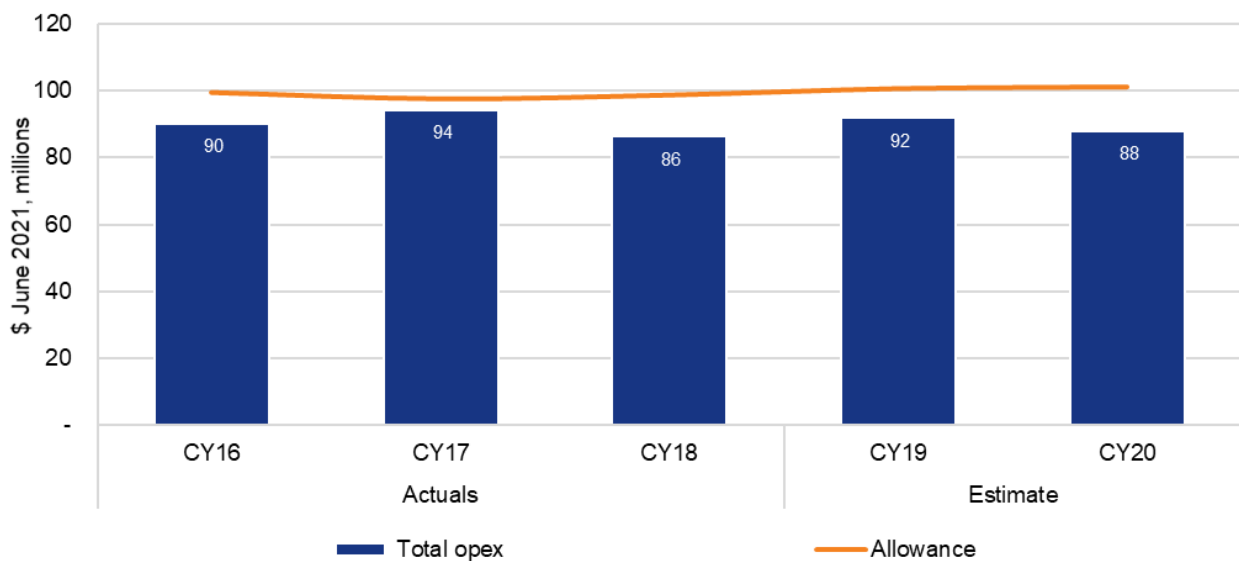
4.2 Selection of the base year

We have used CY18 as the base year because it:

- reflects reliable, current and audited recent operating expenditure for JEN
- represents our underlying, current operating conditions in the current regulatory period and what we expect for the next regulatory period
- avoids the impact of transformation costs incurred in CY19, consistent with the AER's guidance in its draft decision for Jemena Gas Networks' (JGN) 2020-25 Access Arrangement (which we discuss in section 4.3)
- is below the efficient operating expenditure allowance set by the AER and our actual operating expenditure in CY16 and CY17
- is consistent with the criteria of efficient operating expenditure benchmarks, and it has the lowest operating expenditure in the current regulatory period (which we discuss further in section 4.4).

Figure 4–2 compares CY18 operating expenditure to that incurred in CY16 and CY17, estimates for CY19 (which includes \$10M transformation costs) and CY20 against the AER's allowance for the current period. This comparison supports our view that CY18 is the appropriate starting point for determining base year operating expenditure for the reasons provided above. Section 4.4 provides further support for our choice of a base year.

Figure 4–2: Comparison of CY18 operating expenditure (\$ June 2021, millions)



Notes – DRC are excluded from the values above.

4.3 Transforming our businesses

We strive to continue to improve our cost-efficiency. We are currently implementing a business-wide transformation program, which aims to reduce our operating-cost base further so that we can achieve sustainable operating-cost reductions over the longer term. The program demonstrates our commitment to continuous improvement in operational efficiency and will assist us in reducing network charges for our customers over the next regulatory period.

The key focus areas of the transformation program are:

- optimisation of corporate activities and improvements to customer service
- procurement and contract renegotiation
- salary restructuring.

However, since the costs of this transformation program were incurred in CY19, our operating expenditure in that year is higher than in CY18. In the draft plan, our preference was to use estimated CY19 excluding transformation costs as the base year as we believed it better represents our ongoing level of operating expenditure in the next regulatory period. Notably, in the AER's draft decision on JGN's 2020-25 Access Arrangement proposal,¹⁷ the AER expressed a preference to choose an alternative base year where one-off factors do not impact the reported costs. In its draft decision for JGN, the AER preferred to use 2017-18 as the base year, where once-off transformation costs did not affect the operating expenditure in that year, instead of 2018-19. The AER explained their approach in JGN's draft decision that:

The actual opex incurred in 2017–18 is similar to the opex reported in previous years and there is no evidence to suggest JGN's expenditure drivers will change materially in the forecast period compared to those in 2017–18. Additionally, it is unaffected by abnormal non-recurrent costs, is not an estimate and has already been audited. [emphasis added]

In light of this, we have aligned our approach to AER's draft decision for JGN and used CY18 as the base year for JEN.

¹⁷ AER, *Draft Decision, Jemena Gas Networks (NSW) Ltd, Attachment 6*, 25 November 2019, pp. 24–25.

4.4 The efficiency of base year

Benchmarking is a useful tool for assessing the efficiency of the base year operating expenditure—and one that the AER is increasingly placing more weight on when setting operating expenditure allowances. While we do not believe that benchmarking should be used deterministically to set those allowances, it is a tool that combines various techniques to inform whether an electricity distribution network service provider's (DNSP) revealed operating expenditure is appropriate to use as the base operating expenditure when applying the *base, step and trend* approach.

In our case, the CY18 actual operating expenditure is consistent with efficient benchmarks and performance of our network peers—a view supported by:

- the AER's CY19 annual benchmarking report updated for JEN's restated CY18 data (see section 4.4.1), and
- cross-checking against the assessment of the base year determined in the AER's current regulatory period distribution determination for JEN and some variations to the existing benchmarking models (see section 4.4.2).

We understand that benchmarking results are important and support the AER in continually developing and improving these techniques. We also agree with the AER in not applying these techniques deterministically and taking a holistic view of overall cost efficiency¹⁸. For example, in JEN's final decision for the current regulatory period the AER states:

*"We have used several assessment techniques that enable us to estimate the benchmark opex that an efficient service provider would require over the forecast period. These techniques include economic benchmarking and opex cost function modelling. We have used our judgment based on the results from all of these techniques to holistically form a view on the efficiency of Jemena's proposed total forecast opex compared to the benchmark efficient opex that would be incurred over the relevant regulatory control period."*¹⁸

These comments follow the AER's position in its draft decision for JEN's current regulatory period:¹⁹

"....Jemena is an average performer on opex benchmarking but performs relatively well on total expenditure benchmarking (i.e. MTFP). We do not consider it would be reasonable to conclude Jemena was relatively inefficient when alternative benchmarking models we have produced indicate a different ranking."

and

"In our annual benchmarking report we also present a number of partial performance indicators. These indicators examine the service providers' use of assets, opex and total inputs in delivering its distribution services. Under these metrics, Jemena appears to be one of the more efficient networks. As such, we consider that this benchmarking supports the general conclusion of no evidence of material inefficiency."

We agree with the AER's approach of taking a holistic assessment of benchmarking evidence in determining businesses cost efficiencies. In recent decisions, the AER relied on a broad range of evidence including Multilateral Total Factor Productivity (MTFP), MPFP, Partial Performance Indicators (PPI) and econometric models in assessing DNSPs cost efficiencies. For example in the recent decision for Evoenergy, although its operating expenditure did not fall within the range of efficient operating expenditure derived using econometric models, the AER took a more holistic approach in the assessment and recognised that it was spent within an efficient level of operating expenditure allowance and ranked mid-range on operating expenditure MPFP and hence is not materially inefficient.²⁰

¹⁸ AER, Attachment 7 – Operating expenditure | Jemena distribution determination final decision 2016–20, Table 7.5, p. 28.

¹⁹ AER, Attachment 7 – Operating expenditure | Jemena Preliminary decision 2016–20, p. 36 and 37.

²⁰ AER, Evoenergy 2019-24 - Draft decision - Attachment 6 - Operating expenditure, September 2018, p. 23-26 and AER, Final decision - Evoenergy distribution determination 2019-24 - Attachment 6 - Operating expenditure, April 2019, p. 12.

Similarly, in AER's recent draft decision for Ergon Energy, the AER considered a range of measures including PPI measures such as operating expenditure per customer and category level PPIs, operating expenditure MPFP and econometric models.²¹

4.4.1 Benchmarking of JEN's operating expenditure base year

The AER reports annually on the productivity growth and efficiency of DNSPs. The latest edition is the 2019 annual benchmarking report,²² which was informed by expert advice from Economic Insights.²³ In developing this report, the AER relies on the annual information provided by the DNSPs provided through Regulatory Information Notice (RIN) responses. Since the AER released its report, we made some changes in JEN's historical data and submitted to the AER in November 2019 through an updated RIN response. However, the timeframes did not permit this updated data to be utilised in the AER's 2019 report. To account for the timing in the updating of data, we have refreshed the AER's 2019 annual benchmarking report analysis to reflect this restated data.

JEN's performance varies across the productivity index numbers, operating expenditure econometric modelling and partial performance indicators presented within the AER's benchmarking report. The below Table 4–1 provides a summary of JEN's cost performance across various techniques.

Table 4–1: Summary of JEN's benchmarking performance⁽¹⁾

Benchmark	Type	JEN rank
Total cost per customer	Partial performance indicator	3
Network services operating expenditure per customer	Partial performance indicator	4
SCS operating expenditure per customer	Partial performance indicator	3
Maintenance operating expenditure per customer	Partial performance indicator	1
Maintenance operating expenditure operating expenditure per km of circuit length	Partial performance indicator	7
Vegetation management operating expenditure per customer	Partial performance indicator	2
Vegetation management operating expenditure per km of overhead circuit length	Partial performance indicator	7
Emergency response operating expenditure per customer	Partial performance indicator	2
Total cost per mega-watt of maximum demand	Partial performance indicator	5
MTFP (Total cost) ⁽²⁾	Productivity index	6
MPFP Capital cost	Productivity index	4
MPFP operating expenditure	Productivity index	10
MTFP (Total cost) – original output weights ⁽³⁾	Productivity index	4
MPFP Capital cost – original output weights	Productivity index	4
MPFP operating expenditure – original output weights	Productivity index	9
SFA – CD – 2006-18 sample	Econometric model	7
SFA – TL – 2006-18 sample	Econometric model	8
LSE – CD – 2006-18 sample	Econometric model	8
SFA – CD – 2012-18 sample	Econometric model	8

²¹ AER, *Ergon Energy 2020-25 - Draft decision - Attachment 6 - Operating expenditure*, October 2019, p. 27-44.

²² AER, *2019 annual benchmarking report, Electricity distribution network service providers*, November 2019.

²³ Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2019 DNSP Annual Benchmarking Report*, 5 September 2019.

Benchmark	Type	JEN rank
SFA – TL – 2012-18 sample	Econometric model	11
LSE – CD – 2012-18 sample	Econometric model	8
Average Econometric models and MPFP (2006–18 average)	Econometric model & Productivity index	9
Average Econometric models and MPFP (2012–18 average)	Econometric model & Productivity index	11

(1) Based on corrected CY18 data resubmitted to the AER in November 2019.

(2) In AER's 2019 benchmarking report, JEN's rank on MTFP and MPFP operating expenditure was 8 and 13 respectively. JEN subsequently restated its CY18 data which resulted in its ranking improving to 6 and 10 respectively.

(3) The output weights applied during the current regulatory period (see section 4.4.1.2 for more details).

Based on the range of benchmarking analysis provided in the table above, the key outcomes on JEN's operating expenditure performance are:

- JEN benchmarks among top 3 to 4 DNSPs on operating expenditure per customer and is the top performer on maintenance operating expenditure per customer
- It ranks third on the total cost per customer, ranks fourth on MTFP based on original output weights and sixth on new weights
- Our benchmarking rankings on operating expenditure alone using MPFP and econometric methods ranges from seventh to eleventh, with JEN's median rank being eighth
- Based on the average of econometric models and MPFP using a 2006-18 sample, JEN ranks ninth. It ranks eleventh when using the 2012-18 sample
- We rank fourth on capital expenditure MPFP under both original and new output weights
- JEN ranks second on both vegetation management cost per customer and emergency cost per customer.

From JEN's strong total cost benchmarking performance—including total cost per customer and MTFP—we believe JEN is a cost-efficient business overall. We consider that the variability in JEN's operating expenditure ranking may be due to a range of factors such as models that may not perfectly allow for JEN's operating expenditure drivers, changes in output weights, revisions to the international dataset, differences in capitalisation policies or operating environment conditions such as JEN having a high proportion of overhead transmission lines. Nevertheless, the assessment of total cost reveals that JEN is an efficient business despite its small scale and not having the advantage of spreading its electricity field force, maintenance and network operating expenses across multiple utilities in the same geographical area like its counterparts in Victoria.

Given the results on ranking do vary significantly with the technique applied to data, it is therefore essential to take a holistic view to assess operating expenditure efficiency, considering a range of perspectives and avoid relying on a single measure. It is also crucial to evaluate the capital expenditure and operating expenditure together in determining the overall efficiency of a business to take account of any capital expenditure-operating expenditure trade-offs.

Further, outcomes from efficiency methods and approaches are sensitive to assumptions and weights. In its most recent benchmarking report the AER noted its intent to review its economic benchmarking practice further and stated several items which have the potential to impact benchmarking outcomes materially:²⁴

- the implications for cost allocation and capitalisation differences on the benchmarking results.
- the review of benchmarking output specifications
- the choice of benchmarking comparison point

²⁴ AER, 2019 annual benchmarking report, *Electricity distribution network service providers*, November 2019, pp. v, 40–49 and 27.

- improving and updating the quantification of material operating environment factors.

We agree that these are essential areas to focus on and reinforce our view that caution should be used when relying on economic benchmarking outputs.

4.4.2 Cross-checking our efficiency assessment of JEN's base year

We also cross-checked our assessment of JEN's efficient base year by:

- adopting the same assessment approach that the AER took to reviewing the base year for the current regulatory period (section 4.4.2.1)
- comparing JEN's total cost and operating expenditure per customer (controlled for customer density) (section 4.4.2.2)
- assessing JEN's efficiency when businesses are split into rural and urban sub-samples (section 4.4.2.3).

4.4.2.1 Cross-check with AER's CY14 base year decision

When considering the CY14 base year for JEN's current regulatory period, the AER assessed JEN's efficiency based on total cost performance and concluded that JEN is an efficient business. In doing so, the AER relied on MTFP and total cost per customer measures.

In assessing the MTFP measure for CY14, it applied output weights that gave higher weight to customer numbers—a crucial driver of JEN's operating expenditure due to significant growth in its network area. JEN benchmarked fourth and was among the top five most efficient businesses on a total cost basis.

However, the weights applied from CY18 onwards have been updated, with reduced weight on customer numbers, and increased weight on circuit length²⁵ and ratcheted maximum demand. This change lowered JEN's rank from fourth to sixth. However, if we apply the CY14 weights to CY18 MTFP, JEN would still benchmark fourth on CY18 operating expenditure data.²⁶ This approach gives us confidence that our performance has not deteriorated between CY14 and CY18.

Given this outcome, we believe our assessment approach and conclusion that CY18 is an efficient base year is consistent with AER's assessment of our CY14 operating expenditure.

4.4.2.2 Cross-check with the total cost and operating expenditure per customer

In the AER's 2019 benchmarking report, the PPIs are presented together with customer density to visually show the cost performance of each business recognising the potential variability of costs against customer density across networks.

To make this PPI measure directly comparable amongst networks when customer density is taken into account, we have plotted the best-fit line of the total cost per customer and operating expenditure per customer against customer density.²⁷ The best-fit line represents the average performance of all networks when customer density is controlled for. The result in Figure 4–3 shows that JEN's total cost per customer is below the best-fit line, indicating that JEN is more efficient than its peers on a total cost basis. For operating expenditure per customer, as shown in Figure 4–4, JEN is below the best-fit line, indicating that JEN incurs lower operating expenditure per customer when compared with its peers.

²⁵ It should also be noted that JEN's ongoing Preston Conversion program of replacing old 6.6 kV lines with the 22 kV modern equivalents reduces our overall circuit length, and this adversely impacts benchmarking results despite not being an indicator of lower operating efficiency.

²⁶ JEN's operating expenditure MPFP rank improves from 10th to 9th for 2018 when using the 2014 output weights.

²⁷ The best-fit lines for both total cost per customer and operating expenditure per customer against customer density are statistically significant at the 5 per cent level.

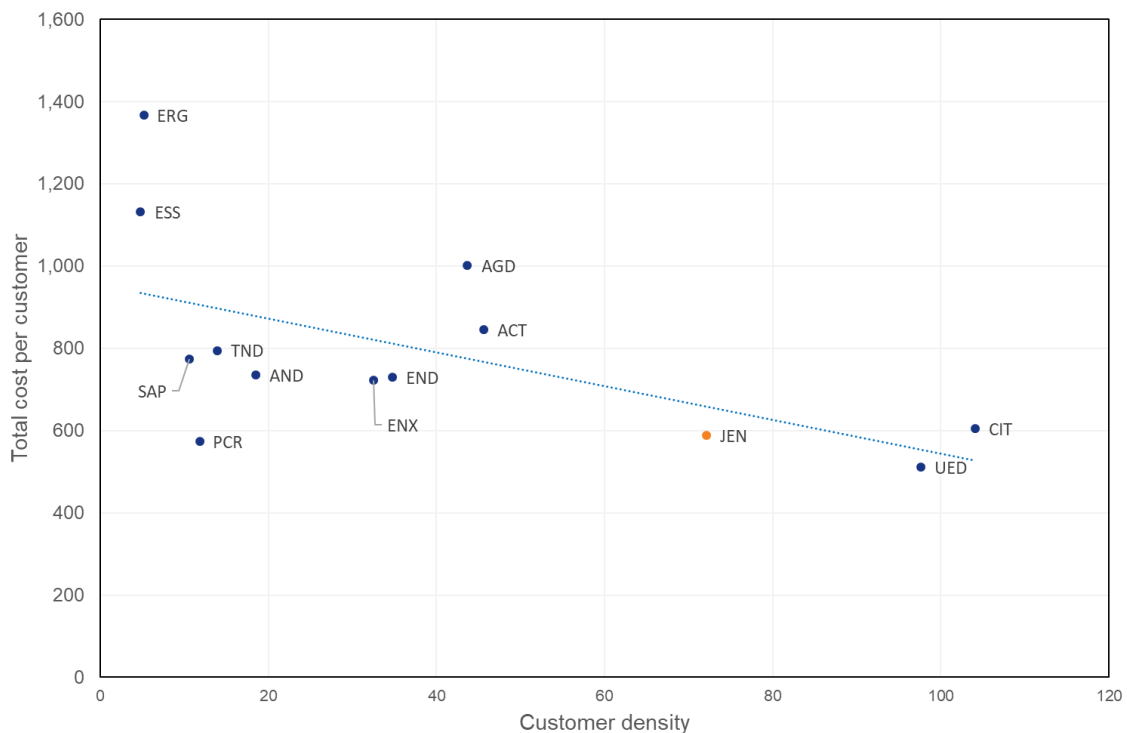
JEN benchmarks strongly on category level operating expenditure. As shown in Table 4–1, JEN is the top performer on maintenance costs per customer and second on both vegetation management and emergency response costs per customer.

The AER in its draft decision for JEN’s current regulatory period states that²⁸:

“Although a number of PPIs are presented in this report we consider that the most relevant PPIs are opex per customer and total cost per customer. This is because customer numbers appears to be the most material driver of costs for service providers.”

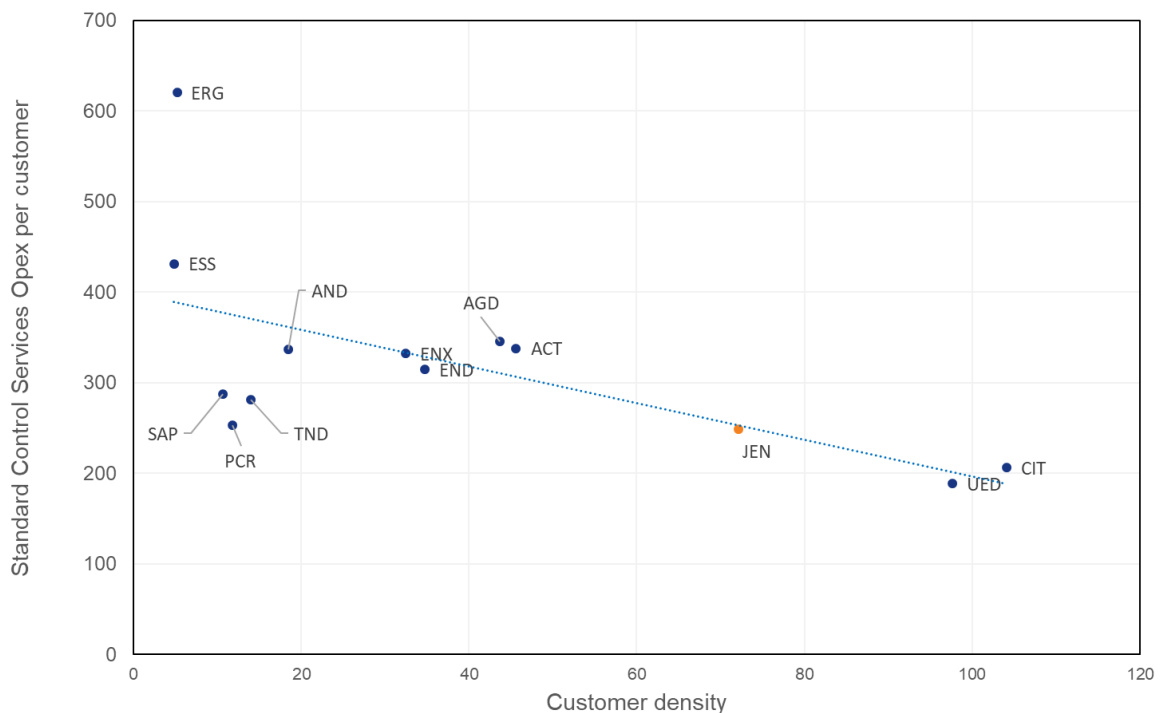
This cross-check on cost per customer supports JEN’s efficiency from both total cost and operating expenditure perspectives. JEN not only ranks in the top quartile on cost per customer measures but also outperforms its peers when customer density has been accounted for.

Figure 4–3: Total cost per customer with best-fit line



Source: AER Benchmarking dataset with restated JEN RIN data

²⁸ AER, Attachment 7 – Operating expenditure | Jemena Preliminary decision 2016–20, p. 37.

Figure 4–4: SCS operating expenditure per customer with a best-fit line

Source: AER Benchmarking dataset with restated JEN RIN data

4.4.2.3 Cross-check splitting out rural and urban networks

To account for the different characteristics of urban and rural networks in operating expenditure spending, we re-estimated JEN's operating expenditure efficiency using the SFA CD model by splitting DNSPs into urban and rural sub-samples based on customer density (DNSPs are designated as rural if they have less than 20 customers per km of circuit length²⁹, and as urban otherwise). The rationale for doing so is to account for the fact that the impact of different cost drivers on reported costs might differ across networks with different customer densities.

The result shows that the impact of cost drivers on reported costs differ between rural and urban networks. For urban businesses (including JEN) more weights are assigned to customer numbers, and for rural network businesses, more weights are assigned to circuit length. When this difference in network characteristics is taken into account, JEN ranks amongst the top 4 most efficient DNSPs (within the top quartile).

This cross-check supports JEN's operating expenditure efficiency and that JEN's CY18 operating expenditure is an efficient operating expenditure to be used as the base year for forecasting allowances over the next regulatory period.

4.5 Adjustments to the base year

4.5.1 Final year adjustment

The AER's operating expenditure model estimates final year operating expenditure—CY20 in our case—by adding an increment of the difference between the AER's allowances between the base year and final year onto our efficient base year (CY18) operating expenditure. This adjustment is summarised in Table 4-2 and is consistent with how the EBSS is applied (as discussed in Attachment 07-05 *Incentive mechanisms*).

²⁹ This split was chosen to get reasonable number for rural and urban Australian businesses (7 urban and 6 rural).

Table 4-2: Final year adjustment (\$ June 2021, millions)

	AER operating expenditure allowance	Less operating expenditure for categories specifically forecast
CY18	98.74	-0.91
CY20	101.24	-0.99
Final year adjustment (CY20 less CY18)	2.50	-0.07

Note – The final year adjustment for operating expenditure categories forecast is explicitly included within the 'Remove estimated final year operating expenditure for categories forecast specifically' adjustment included in the operating expenditure model (Attachment 06-04 SCS *opex model*). The operating expenditure model reports values in dollars as of 31 December 2020, which have been converted to dollars as at 30 June 2021 in this table.

4.5.2 Expensing of corporate overheads

Corporate overheads are costs associated with corporate functions that are necessary to provide our SCS. In the past, and in the current regulatory period, we have typically capitalised approximately 30 per cent of our SCS corporate overheads.

We are changing the treatment of these corporate overheads for regulatory purposes so that, from 1 January 2021, all of these costs will be expensed to align the treatment of these costs with our future CAM, which was approved by the AER 1 May 2019.³⁰

Recognising that we do not earn a rate of return on operating expenditure, this change in the treatment of these costs will benefit customers in the longer term, as it will result in a lower Regulatory Asset Base (**RAB**) and therefore have a downward impact on network prices over the long-term. The effect of this change is to increase our operating expenditure base by \$12M per annum or \$62M in total.³¹

This change reduces our capital expenditure by the same amount and so does not reflect any change in our overall costs or efficiency.

³⁰ AER, *Final Decision, Jemena Electricity Networks (Vic) Ltd Revised Cost Allocation*, May 2019.

³¹ We applied the capitalised overheads forecasting method outlined in section 3.3.3 of Attachment 05-01 to estimate the capitalised corporate overheads in CY20. This estimated amount was then removed from our capital expenditure forecast and moved into our operating expenditure forecast from 1 Jan 2021 onwards. Please refer to *Attachment 05-11 Capex Model – 20200131 – Public* for more details on this calculation.

5. Trending the base year

5.1 Total trend

The *base, step and trend* approach adjusts the base year for the expected rate of change over the next regulatory period. In its recent decisions—including for our current regulatory period—the AER has defined three components of the rate of change adjustments to the base year.

- **Input cost trend**—this is the expected change in our real cost of inputs, such as labour and materials, over the next regulatory period, which are primary inputs to our operating expenditure program (see section 5.2)
- **Output growth trend**—this captures the incremental cost of the expected change in the level of our activity over the next regulatory period, as measured by the change in our customer numbers, circuit length, ratcheted maximum demand and energy throughput (see section 5.3)
- **Productivity trend**—this is the expected reduction in our costs over the next regulatory period due to developments in technology and other factors that enable us to provide our service at a lower cost (see section 5.4).

The following rate of change relationship determines the trending of our base year operating expenditure:

$$\text{Annual real rate of change} = (1 + \text{input cost growth}) \times (1 + \text{output growth}) \times (1 - \text{productivity growth}) - 1$$

We have applied these three trending adjustments to our base year forecast for the next regulatory period and the January to June 2021 half-year period.³² Table 5-1 shows the impact on our operating expenditure forecast.

Table 5-1: Forecast rate of change

	FY22	FY23	FY24	FY25	FY26
Input cost trend	0.59%	0.61%	0.64%	0.64%	0.65%
Output growth trend	1.20%	1.31%	1.32%	1.27%	1.27%
Productivity adjustment	-0.50%	-0.50%	-0.50%	-0.50%	-0.50%
Total operating expenditure rate of change	1.29%	1.42%	1.46%	1.41%	1.42%

Table 5-2 shows the value of the forecast rate of change, excluding inflation, over the next regulatory period. These cost drivers will increase our operating expenditure by an average of 1.4 per cent per annum in the next regulatory period.

³² The rate of change factors are applied in the January to June 2021 period because base operating expenditure is set as at CY20. To convert this into a forecast over the next regulatory period—which is in financial years—an additional half year trend is required to move from CY20 to FY22.

Table 5–2: Forecast rate of change (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Input cost trend	0.9	1.5	2.2	2.8	3.5	10.8
Output growth trend	2.0	3.3	4.7	6.1	7.5	23.6
Productivity	-0.5	-1.0	-1.6	-2.1	-2.7	-8.0
Total operating expenditure trend	2.3	3.8	5.3	6.8	8.3	26.4

We explain each of these forecasts in the following sub-sections.

5.2 Input cost trend

Our base year operating expenditure reflects the current prices of our inputs, which comprise labour and non-labour items, such as materials. The base, step and trend approach allows for our adjusted base year operating expenditure to be varied to account for forecasting real changes in input costs.

We have applied the AER's standard approach of using a weighted average of forecast labour and non-labour cost growth to determine our overall input cost growth adjustment. We have developed our operating expenditure forecast on the assumption that our real labour costs will increase, but our other non-labour input costs will not change in real terms (i.e. they will move in accordance with inflation).

As shown below, input costs contribute an increase of \$11M to forecast operating expenditure over the next regulatory period. In recent draft decisions,³³ the AER has proposed changing how it forecasts labour input costs, which we discuss in section 5.2.2.

5.2.1 Impact of real input costs trend

Our input cost adjustments are based on forecast real price increases in labour rates of between 0.99 per cent and 1.08 per cent per annum for the next regulatory period, as detailed in Table 5–3. This adjustment reflects:

- the average of real labour escalator forecasts from BISOE and DAE. We have relied on forecasts by BISOE (see Attachment 05-07) and have relied on DAE's real wage price index (**WPI**) forecasts for the NSW utilities' industries commissioned by the AER³⁴ as a placeholder. We have used these as proxies for our labour costs over the next regulatory period.
- our assumption about the relative weighting of 59.7 per cent for labour and 40.3 per cent non-labour to our operating expenditure costs, which is the benchmark weightings in AER's 2017 Economic Benchmarking report³⁵ and applied to electricity distribution businesses in the AER's recent decisions.³⁶

³³ See, for instance, AER, *SA Power Networks 2020-25 – Draft decision – Attachment 6 – Operating expenditure*, November 2019, pp. 28-32.

³⁴ Deloitte Access Economics, *Labour Price Growth Forecasts prepared for the AER*, 24 June 2019 Section 3.2.4, p. 23.

³⁵ Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report*, 31 October 2017, pp. 1–2.

³⁶ AER, *Ausgrid 2019-24 – Draft decision – Attachment 6 – Operating expenditure*, November 2018, p. 37; AER, *Essential Energy 2019-24 – Draft decision – Attachment 6 – Operating expenditure*, November 2018, p. 27; AER, *Endeavour Energy 2019-24 – Draft decision – Attachment 6 – Operating expenditure*, November 2018, p. 31; and AER, *SA Power Networks 2020-25 – Draft decision – Attachment 6 – Operating expenditure*, November 2019, p. 33.

Table 5–3: Forecast input cost growth

	FY22	FY23	FY24	FY25	FY26	Total
BISOE real labour forecast (A)	1.48%	1.65%	1.64%	1.45%	1.46%	
Deloitte Access Economic real labour forecast (B)	0.50%	0.40%	0.50%	0.70%	0.70%	
Average real labour forecast (C = (A+B)/2)	0.99%	1.02%	1.07%	1.08%	1.08%	
Labour contribution to Input Price growth trend (D)	59.70%	59.70%	59.70%	59.70%	59.70%	
Adjusted real labour forecast (E=D x C)	0.59%	0.61%	0.64%	0.64%	0.65%	
Real other forecasts (F)	0.00%	0.00%	0.00%	0.00%	0.00%	
Input Price growth trend (E+F)	0.59%	0.61%	0.64%	0.64%	0.65%	
Input cost growth (\$ June 2021, millions)	0.9	1.5	2.2	2.8	3.5	10.8

5.2.2 The AER is considering changes to real wage-price escalation

In its draft decisions for SA Power Networks, Energex and Ergon Energy's 2020-25 regulatory periods, the AER relied solely on DAE's labour escalation forecasts—a departure from its past practice. In decisions before these, the AER used an average of DAE and BISOE's WPI forecasts to determine a labour escalator for its regulatory decisions (for example, the decision for JEN over the current regulatory period³⁷).

To support its proposed change, the AER relied on analysis testing how various forecasts provided by each of DAE and BISOE compared to actual labour escalation (as estimated by the Australian Bureau of Statistics (ABS)). Its analysis was based on WPI growth forecast reports for the 2007 to 2018 years and found that BISOE's forecasts were less accurate than DAE's.

However, the AER did not test whether its new proposed approach (using DAE only) was more accurate than the past method (averages of DAE and BISOE) for relevant regulatory determinations. Indeed, the AER did undertake this analysis previously and clearly identified that averaging multiple forecasts yielded better results than a single forecast.³⁸ Given this conclusion, and in the absence of any new information to indicate why this position should change, it is difficult to see how the AER's analysis supports its proposed change. We consider that relying on this approach to support a proposed change to just one forecast without testing how the average performs is premature and inconsistent with best practice.

The Victorian Electricity Distribution Businesses have engaged Frontier Economics³⁹ to review AER's analysis from a Victorian perspective. Additionally, CEPA⁴⁰ and BISOE⁴¹ have considered the AER's analysis, focusing on identified issues with the proposed methodology.

In its review of the AER's analysis, Frontier Economics concluded that:⁴²

³⁷ AER, *FINAL DECISION, Jemena distribution determination, 2016 to 2020, Attachment 7 – Operating expenditure*, May 2016, p. 7-24.

³⁸ AER, *Powerlink Final Decision 2013-17*, April 2012, p. 54.

³⁹ Attachment 07-02; Frontier Economics, *Assessment of the AER's approach to forecasting labour escalation rates, A report prepared for Ausnet Services, Citipower, Jemena, Powercor and United Energy*, December 2019.

⁴⁰ CEPA, *Review of AER's approach to JGN cost escalators*, 19 December 2019.

⁴¹ BISOE, *Review of AER wage forecast comparison*, December 2019.

⁴² Frontier Economics, *Assessment of the AER's approach to forecasting labour escalation rates, A report prepared for Ausnet Services, Citipower, Jemena, Powercor and United Energy*, December 2019, p. 2.

the AER's decision to rely exclusively on the forecasts of labour cost escalations produced by a single adviser, rather than follow its previous approach of averaging forecasts produced by different advisers, is unreasonable. The AER should revert to the practice it has followed since 2013 and adopt the average of forecasts produced by different advisers when setting real labour cost escalation rates.

Frontier Economics supports the conclusion that combined forecasts are likely to be more accurate than individual forecasts by referencing a well-known review of the forecasting literature, which concludes that:⁴³

The results have been virtually unanimous: combining multiple forecasts leads to increased forecast accuracy. In many cases one can make dramatic performance improvements by simply averaging the forecasts.

Another crucial finding from Frontier Economics is that the AER should not use national data as a proxy for jurisdictional forecasts. The Frontier report states:⁴⁴

There is no evidence that DAE has been a more accurate forecaster of the real EGWWS WPI for Victoria than BIS. To the contrary, BIS appears to have been the more accurate forecaster—the empirical evidence shows that BIS's forecasts of the real growth in the Victorian EGWWS WPI have greater accuracy than DAE's forecasts. That suggests that discarding BIS's forecasts for Victoria would be inappropriate.

And:⁴⁵

For Victoria, the evidence suggests that the average of DAE's and BIS's past forecasts would have resulted in more accurate outcomes than exclusive reliance on either of those advisers' forecasts individually.

In a recent review for JGN's revised proposal, CEPA noted several issues with the AER's analysis. CEPA has pointed out the inconsistency in the AER's approach on estimating WPI and CPI expectations. In the case of assessing CPI forecasting measures, the AER notes that:⁴⁶

"We are required to estimate expected inflation in our regulatory framework, but the inflation outcome may turn out to be different to the original expectation. A difference between an initial expectation and the ultimate outcome does not necessarily mean that the expectation was not the best possible expectation available at the time"

However, the AER has not applied the same principle to assessing WPI measures. In particular, the AER notes that:⁴⁷

"...we recently analysed the accuracy of these two forecasters over the period 2007 to 2018 and found BIS Oxford over forecast WPI growth. Consequently, we do not consider BIS Oxford's WPI, nor an average of BIS Oxford's and Deloitte's represents the best forecast in the circumstances. We have forecast labour price growth using only Deloitte's forecasts"

CEPA concludes that as both wages and consumer price inflation should be considered based on an expectation, it is reasonable that forecasts should be considered on the same basis. Therefore, CPI and WPI should be assessed in the same way, i.e. either by choosing the most accurate measure against outturn, or the most appropriate for forecast expectations.

⁴³ Clemen, R. (1989), Combining forecasts: A review and annotated bibliography with discussion, International Journal of Forecasting 5(4), pp. 559–583.

⁴⁴ Attachment 06-02 Expert opinion on real price escalation, p. 2.

⁴⁵ Attachment 06-02 Expert opinion on real price escalation, p. 2.

⁴⁶ AER, Attachment 6: Operating expenditure | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25, November 2019, p. 6-22.

⁴⁷ AER, Attachment 6: Operating expenditure | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25, p. 22.

CEPA also highlights that while DAE may have a lower absolute mean error over a certain period, it is not necessarily true that it has always had a smaller absolute mean error compared to BIS at all times. Therefore it cannot be concluded that DAE's forecast is a better measure based on its performance over a particular period. We agree with CEPA and consider that an average of the two measures is likely to lower any significant bias in forecast measures.

There is also precedent in other areas of the AER's decision making for using averages across estimates or forecasts. CEPA notes:⁴⁸

For example, for estimating the allowed return on debt, the AER averages data from three third party data providers: the RBA, Bloomberg and Thomson Reuters.⁴⁹ In their averaging the AER puts equal weight on each of the data providers. The AER concluded that a decision to put equal weight on all providers was justified as each provider had unique strengths and weaknesses, an equal weight was intuitively reasonable, and any weighting scheme would rely on contentious assumptions.⁵⁰

From an electricity distribution network perspective, JEN notes that the AER draws from four different models when conducting its operating expenditure benchmarking analysis to minimise errors associated with any one model; this is an *increase* in the number of inputs used to determine the forecasts, as opposed to the *decrease* in inputs used in the input price escalation in SAPN, Ergon Energy and Energex draft decisions.

BISOE also reviewed the AER's analysis. The key conclusion from BISOE is that departing from the AER's previous approach—of averaging the projections produced by DAE and BISOE for growth in the all-industries and the EGWWS real WPI) and instead relying only on the DAE projections for these series—is statistically likely to result in a worse outcome (in terms of forecasting accuracy).⁵¹ BISOE found the following issues with the AER's analysis:⁵²

The approach undertaken by the AER attaches an equal weight to all forecasts, irrespective of their forecast horizon. For example, they equally weight a projection for the current year with a projection for five years ahead. Given the inherent uncertainty surrounding forecasting, and the fact that this uncertainty increases with the length of forecast horizon, it is important to consider performance by forecast horizon.

And:⁵³

The dataset used by the AER in its analysis is asymmetric. In some cases, forecasts from the same firm were drawn from consecutive months (and we would expect these forecasts to be very similar given the timing), which will result in these particular forecasts effectively having a higher-than-average weight in the calculations of forecast performance. The overweighting of these forecasts (and implied underweighting of others) could result in biased results.

BISOE also found that DAE's forecasting record is not superior due to superior modelling of utility sector wages. The performance—as analysed by the AER—was the result of its incorrect modelling of the relationship between utilities and all-industries wages, which was offset by its over-estimation of all-industries wages. These two errors effectively off-set each other, resulting in a better apparent forecasting performance for the EGWWS WPI.

To this point, BISOE notes that:⁵⁴

When looking at the historical forecast performance of both firms together, the average forecast performance is materially better than either firm individually. This is because the tendency to

⁴⁸ AER, *Attachment 6: Operating expenditure | Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2020-25*, p. 12,

⁴⁹ AER, *Rate of Return Instrument*, December 2018.

⁵⁰ AER, *Draft – Rate of Return Guidelines – Explanatory Statement*, July 2018, p. 58.

⁵¹ BISOE, *Review of AER wage forecast comparison*, December 2019, p. 3.

⁵² BISOE, *Review of AER wage forecast comparison*, December 2019, p. 3.

⁵³ BISOE, *Review of AER wage forecast comparison*, December 2019, p. 3.

⁵⁴ BISOE, *Review of AER wage forecast comparison*, December 2019, p. 22.

understate the EGWWS gap from DAE is offset against the tendency to overstate the EGWWS gap by BISOE.

Based on these conclusions from Frontier, CEPA and BISOE, we do not consider that the approach adopted by the AER in recent draft decisions—that is, to adopt the forecast of a single forecaster—to forecast real wages growth will result in the best forecast or estimate possible in the circumstances.

5.3 Output growth trend

Our adjusted base year operating expenditure reflects the current level of outputs that we deliver via our services. The base, step and trend approach allows for varying the adjusted base year operating expenditure to account for forecast changes in outputs. This approach is used because many of our operating expenditure activities (and associated costs) will grow in line with our customer base and the length of the network we need to maintain.

We have applied the AER's standard outputs approach relied on in its annual benchmarking reports to determine the forecast changes in outputs. We have calculated the impact on operating expenditure by multiplying the forecast increase in each output measure by the corresponding output weights from five different models as per the AER's 2019 benchmarking report.

Table 5–4: Forecast output weights over the next regulatory period

	SFA CD	LSE CD	LSE TLG	SFA TLG	Operating expenditure MPFP
Customer numbers	67.43%	68.95%	52.95%	69.51%	31.00%
Circuit length	15.08%	15.56%	15.74%	14.84%	29.00%
Ratcheted maximum demand	17.50%	15.48%	31.31%	15.65%	28.00%
Energy throughput	0.00%	0.00%	0.00%	0.00%	12.00%

The results are detailed in Table 5–5. This outcome translates to a 1.20 per cent to 1.32 per cent annual increase in operating expenditure due to output growth over the next regulatory period.

Table 5–5: Forecast output growth over the next regulatory period

Category	FY22	FY23	FY24	FY25	FY26	Total
Customer numbers	1.46%	1.46%	1.45%	1.46%	1.37%	
Circuit length	1.78%	1.91%	1.86%	1.73%	1.67%	
Ratcheted maximum demand	0.00%	0.39%	0.62%	0.45%	0.74%	
Energy throughput	1.46%	1.57%	0.61%	0.62%	0.67%	
Forecast output growth	1.20%	1.31%	1.32%	1.27%	1.27%	
Forecast output growth (\$ June 2021, millions)	2.0	3.3	4.7	6.1	7.5	23.6

5.4 Productivity

In its Final Decision on forecasting productivity growth, the AER decided on a 0.5 per cent per annum operating expenditure productivity growth factor to apply to electricity distribution businesses.⁵⁵

We have incorporated this 0.5 per cent per annum productivity growth forecast into our operating expenditure forecast. This reduction in operating expenditure—arising from forecast productivity gains—is passed directly through to our customers and reflects JEN's commitment to efficiently managing our business. These savings will translate into a reduction of \$8M over five years.

We note that in our draft plan, we adopted the AER's draft decision on the productivity of 1 per cent per annum. At the time, we noted that we did this as a placeholder pending the outcomes of the AER's final decision.

Table 5–6 details the value of our forecast productivity adjustments for the next regulatory period. The productivity amount increases each year because of the cumulative effect of applying the productivity factor on each regulatory year after applying the productivity factor on the previous regulatory year.

Table 5–6: Forecast productivity adjustment (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Annual productivity adjustment from the commencement of the next regulatory period.	-0.5	-1.0	-1.6	-2.1	-2.7	-8.0

⁵⁵ AER, *Forecasting productivity growth for electricity distributors*, March 2019, p. 10.

6. Step changes

The base, step and trend approach allows for adjustments to costs, which could either be positive or negative, that are not reflected in the base year operating expenditure. These changes could arise due to external factors such as new regulatory obligations, legislative impacts, outcomes from customer engagement or other external factors the AER considers to be relevant. These changes could also be a result of internal factors such as efficient trade-offs between capital expenditure and operating expenditure (for example, where demand management is used as a substitute for capital expenditure), where these are not captured in our efficient base year or trend escalation.

As summarised in Table 6–1, we are proposing seven individual step changes for the next regulatory period. These have a total expected cost of \$42M (see Table 6–2 which summarises the annual expenditure profile for each of the step changes proposed)

The drivers for each step change are described in more detail within Attachment 06-05 *Operating expenditure step changes*.

Table 6–1: Proposed step changes (\$ June 2021, millions)

Step change	Value	Description	Support
Insurance premium	28.8	Increases in global concern about catastrophic events, such as bushfires, has increased the insurance premiums we necessarily incur to mitigate against such risks.	Attachment 06-05 <i>Operating expenditure step changes</i> and Attachment 06-06 <i>Insurance premium forecast report</i> .
REFCL testing & maintenance	1.3	Victoria's <i>Electricity Safety (Bushfire Mitigation) Regulations 2013</i> require JEN to install rapid earth fault current limiters (REFCL) by 1 May 2023 Although installation is a capital cost, the REFCL assets will require testing and maintenance once installed and each year after that.	Attachment 05-01 <i>Forecast capital expenditure report</i> The AER approved equivalent incremental operating expenditure in its contingent project application decisions for Powercor and AusNet Services' REFCLs.
Future Grid program	3.8	Activities designed to increase the ability of our distribution network to host distributed energy resources (DER), in line with our customers' forecast uptake of DER.	Attachment 05-04 <i>Future grid investment proposal</i> and Attachment 06-05 <i>Operating expenditure step changes</i> .
Transitional return on debt alignment costs	0.9	The change to the regulatory year from calendar years to financial years creates a six-month gap between its existing return on debt hedges and return on debt averaging periods over the next regulatory period To ensure that JEN's financial positions remain aligned over to those averaging periods, we need to enter new interest rate swaps—which comes at an additional cost.	Attachment 06-05 <i>Operating expenditure step changes</i> .
EPA regulation changes	4.2	Victoria's <i>Environment Protection Amendment Act 2018</i> increases the environmental obligations that JEN faces. Complying with these changes requires JEN to develop plans, undertake studies and risk assessments, and adopt monitoring that it has not previously done.	Attachment 06-05 <i>Operating expenditure step changes</i> .

Step change	Value	Description	Support
Cyber-security	2.9	Heightened cybersecurity risks and clear guidance from the Australian Energy Market Operator (AEMO) and other cybersecurity bodies have increased customer, governmental and community expectations about what IT security protections JEN has in place. JEN's current cybersecurity measures do not meet these expectations and so more needs to be done.	Attachment 06-05 <i>Operating expenditure step changes</i> .
Additional RIN reporting	0.5	Changes to the regulatory year applying to JEN from the start of the next regulatory period—from calendar years to financial years—will require it to undertake additional regulatory reporting. This reporting will lead to one-off expenditure in FY22 financial year related to preparing RIN responses for the six months to June 2021.	Attachment 06-05 <i>Operating expenditure step changes</i> .
Total	42.4		

Table 6–2 summarises the annual expenditure profile for each of the step changes proposed.

Table 6–2: Forecasts step changes (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Insurance Premium	3.9	5.1	6.1	6.6	7.1	28.8
REFCL testing & maintenance	0.0	0.1	0.4	0.4	0.4	1.3
Future Grid program	0.7	0.7	0.8	0.8	0.8	3.8
Transitional return on debt alignment costs	0.1	0.1	0.2	0.2	0.3	0.9
EPA regulation changes	0.8	0.8	0.8	0.8	0.8	4.2
Cyber-security	0.6	0.6	0.6	0.6	0.6	2.9
Additional RIN reporting	0.5	0.0	0.0	0.0	0.0	0.5
Total	6.7	7.5	8.9	9.4	10.0	42.4

7. Specific forecasts

Some operating expenditure categories are better suited to being forecast using approaches other than the base, step and trend because past costs may not be representative of future expenses or it may not be appropriate to apply a trend.

We have used specific approaches to forecasting our GSL payments, ESV distributor levies and debt raising costs. We have used alternative approaches to the base, step and trend method for these costs categories to ensure that the forecast is representative of our future costs or benchmark costs (e.g. in the case of debt raising costs).

This method of forecasting operating expenditure for GSL payments and debt raising costs is consistent with our operating expenditure allowance for the current regulatory period and section 4.4 of our Expenditure Forecasting Methodology submitted in December 2018, while we have adopted a changed approach to forecasting ESV distributor levies for the next regulatory period.

Specific operating expenditure forecasts total \$12M over the next regulatory period, as shown in Table 7–1. These forecasts are further described in the following subsections.

Table 7–1: Forecasts for other cost categories (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
GSL payments	0.2	0.2	0.2	0.2	0.2	0.8
ESV distributor levies	1.4	1.4	1.4	1.4	1.4	6.9
Total (excluding DRC)	1.6	1.6	1.6	1.6	1.6	7.8
Debt raising costs	0.8	0.9	0.9	0.9	0.9	4.4
Total (including DRC)	2.4	2.4	2.4	2.5	2.5	12.1

(1) DRC = debt raising costs

7.1 GSL Payments

We must make payments to customers where we do not meet certain GSL standards. These service standards and payment amounts are set by the Essential Services Commission of Victoria (**ESC**) and are contained in the Electricity Distribution Code.⁵⁶ We have proposed a specific forecast for GSL payments, consistent with our approach in the current regulatory period.⁵⁷

To develop our forecast operating expenditure for GSL payments, we first adjusted JEN's operating expenditure base year to remove expenditure on GSL payments. Our specific forecast of this expenditure reflects the payments we made in our base year CY18, held constant in real terms over the next regulatory period.⁵⁸ We undertake this approach to forecasting GSL payments into the next regulatory period because:

- We assume that our value of GSL payments is relatively even from year to year
- Our forecast operating and capital expenditures are designed to maintain our network's reliability; consequently, we do not see a reason to vary the GSL forecast up or down.⁵⁹

Table 7–2 sets out our specific forecast for GSL payments for each year of the next regulatory period.

⁵⁶ ESC, *Electricity Distribution Code, version 9A*, August 2019, section 6.

⁵⁷ JEN, *2016-20 Electricity Distribution Price Review Regulatory Proposal, Attachment 8-2*, p. 17.

⁵⁸ We incurred GSL payments of \$0.16M in CY18 (\$nominal). We removed the \$0.16M from base operating expenditure and used this number to forecast the GSL payment specific forecast over the next regulatory period (after converting it to dollars as at 30 June 2021).

⁵⁹ More recently, we have become aware that the ESC is undertaking a review of the GSL payment rates and, depending on the outcomes of that review, we may seek to make adjustments to our specific forecast for GSL payments.

Table 7–2: Specific forecast – GSL payments (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
GSL payments	0.2	0.2	0.2	0.2	0.2	0.8

In 2019 the ESC commenced a review of the Electricity Distribution Code. This work includes a review of the Code's customer protections, including GSL payment categories, reliability thresholds, payment amounts and exclusion criteria. This review is ongoing, with a final decision expected in around March or April 2020, after the submission of this regulatory proposal. Should there be any changes to the Code's GSL framework arising from this review, then we will reflect these in our revised regulatory proposal.

7.2 Energy Safe Victoria levy

Under the *Electricity Safety Act 1998* (Vic), each electricity distributor must pay a levy to ESV as determined by the Victorian Minister for Energy, Environment and Climate Change.⁶⁰ These levies are payable annually and are designed to recover the costs of ESV.

These levies have increased materially under recent Ministerial determinations in line with an expansion in ESV's audit, inspection, monitoring and other safety regulation activities in the Victorian energy industry. Given JEN has no control over the levy amounts we are required to pay, we are proposing a specific forecast for this operating expenditure item. This approach represents a change from the current regulatory period.⁶¹

To develop our specific forecast, we first adjusted JEN's operating expenditure base year to remove ESV levy expenditure.⁶² Our specific forecast reflects the annual levy amounts payable by JEN as advised by ESV up to FY21, with the FY21 amount then held constant in real terms from FY22 for the duration of the next regulatory period.⁶³ We forecast the costs will continue at this elevated level based on the heightened focus on safety. For example, the recent Grimes review⁶⁴ identified several reforms in Victoria's Electricity and Gas Network Safety Framework with 21 out of the 43 recommendations being accepted by the Victorian Government.⁶⁵ These reforms, which are still being implemented, will have an enduring cost and operational impact on ESV and our business.

Table 7–3 sets out our specific forecast for ESV electricity distributor levies for each year of the next regulatory period.

Table 7–3: Specific forecast – ESV distributor levy (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
ESV distributor levy	1.4	1.4	1.4	1.4	1.4	6.9

Should this expenditure not be considered appropriate for inclusion as an operating expenditure specific forecast in the AER's draft determination, then alternatively these costs could be recovered through the B-term in the price control mechanism for standard control services—consistent with the approach currently employed in Victoria for recovering annual distribution licence fees for the ESC.

⁶⁰ *Electricity Safety Act 1998* (Vic), s 8.

⁶¹ This expenditure formed part of JEN's base operating expenditure for the current regulatory period.

⁶² This amount was \$1.05M in nominal dollars, or \$1.11M in dollars as at 30 June 2021.

⁶³ ESV, *Proposed levy to apply for period 1 July 2019 – 30 June 2021*, 7 June 2019.

⁶⁴ Dr Paul Grimes, *Independent review of Victoria's electricity and gas network safety framework, Final Report*, December, 2017.

⁶⁵ Department of Environment, Land, Water and Planning, *Government Response to the Independent Review of Victoria's Electricity and Gas Network Safety Framework*, August 2018.

7.3 Debt raising costs

We incur debt raising costs each time we raise or refinance debt. These may include arrangement fees, legal fees, company credit rating fees and other transaction costs. The AER's practice has been to allow DNSPs to recover efficient direct debt raising costs by adding an allowance for them to the operating expenditure forecast.

In its draft decision for JGN in November 2019, the AER adopted an estimate for debt raising costs based on a report by Chairmont which relies on an 'informal' market survey.⁶⁶ We do not consider it consistent with the principles of best practice regulation⁶⁷ (that is, transparent) for regulatory decisions to rely on an approach that is based on informal surveys that cannot be reviewed by businesses—such an approach is in contrast to AER's principles of transparency and predictability that it applies in its decision making.

We asked CEG to review Chairmont's report, and it has found errors in Chairmont's visual data interpretation of publicly available data, and in its regression analysis.⁶⁸ It points out that Chairmont made critical errors in visual data interpretation and concludes that there is no reasonable basis where the publicly available data assessed by Chairmont supports its conclusion of 30 basis points (to be amortised over nine years).

CEG has also recommended the use of the pre-tax weighted average cost of capital (**WACC**) for amortisation as operating expenditure is treated as a tax deduction in the PTRM and that there is a tax deduction for 100 per cent of this compensation. We have provided our new estimate of direct debt raising costs as 8.78 basis points per annum (**bppa**) based on CEG's analysis.⁶⁹

CEG's report—included at Attachment 06-03 *Debt raising transaction costs report*—explains how the debt issuance cost benchmark of 8.78 bppa was determined. Although there are good reasons to include issue price adjustments, liquidity commitment fees, or 3-month ahead financing costs in such a benchmark, we have conservatively only included direct debt raising costs.

Table 7–4 sets out our specific forecast for debt raising costs for each year of the next regulatory period.

Table 7–4: Specific forecast – debt raising costs (\$ June 2021, millions)

	FY22	FY23	FY24	FY25	FY26	Total
Debt raising costs	0.8	0.9	0.9	0.9	0.9	4.4

⁶⁶ Chairmont, *Debt raising costs*, June 2019.

⁶⁷ Council of Australian Governments, *Best practice regulation a guide for ministerial councils and national standard setting bodies*, October 2007.

⁶⁸ CEG, *The cost of raising debt issues*, January 2020. (See attachment 06-03 *Debt raising transaction costs report*).

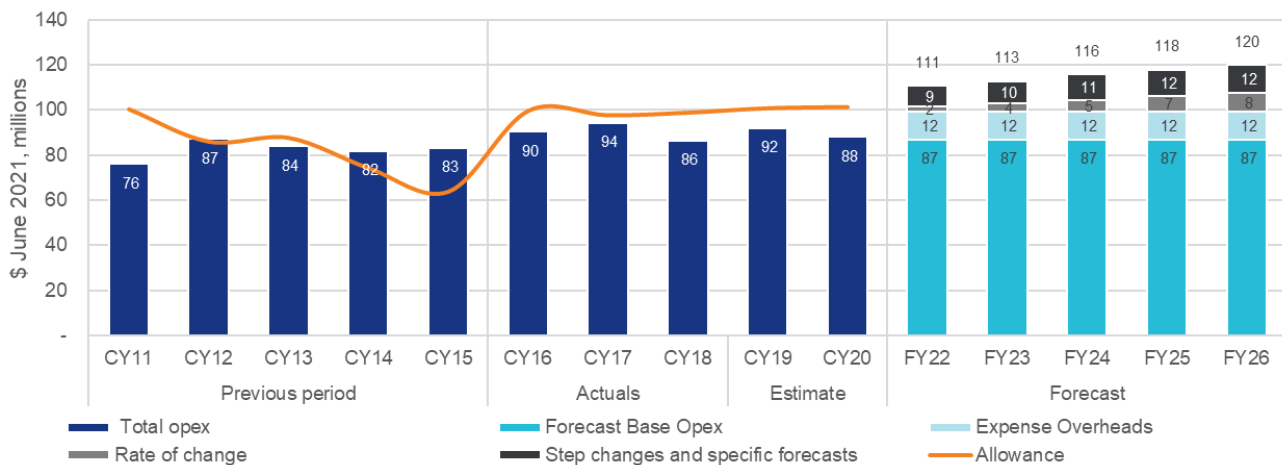
⁶⁹ See Attachment 06-03 *Debt raising transaction costs report*.

8. Our operating expenditure forecast

Our forecast operating expenditure (excluding DRC) for the next regulatory period is \$572M, which is approximately \$122M greater than our actual and estimated operating expenditure for the current regulatory period (see Figure 8–1).

This increase is driven by expensing corporate overheads, new step changes, labour cost escalation and network growth. Taking only JEN's controllable operating expenditure⁷⁰ and excluding the impact of expensed corporate overheads, our forecast operating expenditure will be \$47M higher over the next regulatory period than for our actual and estimated controllable operating expenditure for the current regulatory period.

Figure 8–1: Historical and forecast operating expenditure CY11 to FY26 (\$ June 2021, millions)



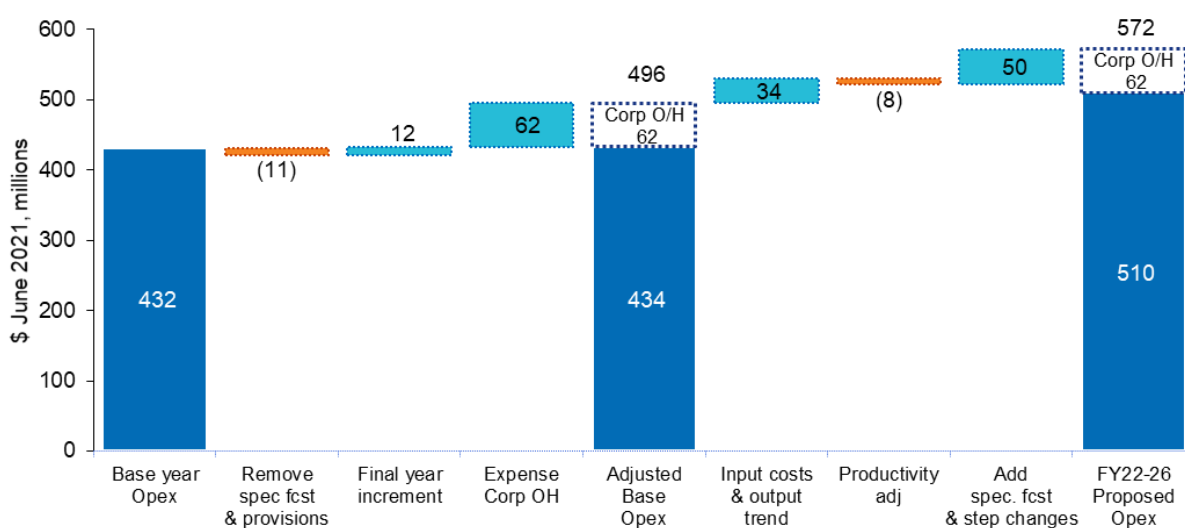
Notes - DRC = Debt raising costs

Figure 8–2 shows that the difference between our operating expenditure in the current and next regulatory periods. The primary reason for the change in expenditure includes:

- an additional \$39M in specific forecasts and step changes, primarily driven by higher insurance premiums, EPA regulation changes, and other regulatory requirements
- the change in the treatment of the corporate overheads from 1 January 2021, which adds \$62M to operating expenditure
- adding \$34M for input cost and scale escalation
- deducting \$8M for the assumed ongoing productivity.

⁷⁰ Controllable operating expenditure excludes category specific forecasts.

Figure 8–2: Comparison of operating expenditure from the base year to the next regulatory period (\$ June 2021, millions, excluding DRC)



Notes - DRC = Debt raising costs, Corp O/H or OH = Corporate overheads, spec fcst = specific forecast, adj = Adjustment

Table 8–1 provides a build-up of each component of our base, step and trend operating expenditure forecasts for the next regulatory period. It also includes the operating expenditure that is forecast using category-specific forecasts (as discussed in section 7) or step change forecasts (as explained in section 6 and Attachment 06 05 *Operating expenditure step changes*).

Table 8–1: Operating expenditure forecasts (\$ June 2021, millions, including DRC)

Category	Next regulatory period								
	CY18	CY19	CY20	FY22	FY23	FY24	FY25	FY26	FY22–26 Total
Base year operating expenditure	88.34	88.57	86.31	86.31	86.31	86.31	86.31	86.31	431.56
Less changes in provisions and DMIA ⁷¹ expenditure	-0.76	-0.76	-0.76	-0.76	-0.76	-0.76	-0.76	-0.76	-3.79
Less specific forecasts	-1.27	-1.38	-1.34	-1.34	-1.34	-1.34	-1.34	-1.34	-6.72
Additional operating expenditure associated with expensing corporate overheads			12.42	12.42	12.42	12.42	12.42	12.42	62.08
Final year adjustment			2.50	2.50	2.50	2.50	2.50	2.50	12.49
Adjusted Base Operating expenditure	86.31	86.42	99.12	99.12	99.12	99.12	99.12	99.12	495.62
Rate of change				2.35	3.79	5.29	6.76	8.26	26.44
Specific forecasts				2.37	2.41	2.44	2.46	2.47	12.15
Step changes				6.68	7.48	8.86	9.40	9.96	42.38
Total				110.51	112.80	115.72	117.74	119.81	576.59

⁷¹ Refer to Attachment 07-05 *Incentive mechanisms* for more details on DMIA.

Appendix A

Compliance with the NER

A1. Compliance with the NER

Our operating expenditure forecasts are prepared on a reasonable basis and were developed to comply with the operating expenditure objectives and operating expenditure criteria and to address the operating expenditure factors⁷² along with other NER criteria for SCS.

A1.1 Operating expenditure objectives

We have established our forecasts to comply with the operating expenditure objectives specified in the NER. This approach was primarily achieved by:

- Examining the proposed base year costs incurred in meeting our current service level and regulatory obligations
- Assessing the sufficiency of our ongoing compliance with safety, regulatory and other compliance obligations to identify step changes for corrective actions
- Determining foreseeable new or changed requirements that will affect our operating activities and costs to identify step changes
- Incorporating escalation or de-escalation for the operating expenditure, rate of change including real price growth, output growth and productivity improvement.

Table A1–1 summarises how we have complied with the operating expenditure objectives.

Table A1–1: Our compliance with the operating expenditure objectives

Operating expenditure objective	Rule	Our compliance
Meet or manage the expected demand for standard control services	6.5.6(a)(1)	We have trended our proposed base year operating expenditure to account for expected changes in output growth drivers such as customer numbers, ratcheted maximum demand, and our network's system physical capacity (see section 5.3).
Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services	6.5.6(a)(2)	We have assessed our current compliance (and associated base year costs), as well as identifying additional new obligations that we expect to be in place over the next regulatory period (see section 0 for our list of proposed step changes).
Maintain the quality, reliability and security of supply of standard control services	6.5.6(a)(3)	We have proactively engaged with our consumers to understand the level of service they value (see Attachment 2–1 <i>Overview of our customer and stakeholder engagement program</i>), to assist the preparation of our next regulatory period proposal. Our customer told us they seek for us to <i>maintain</i> network service levels.
Maintain the reliability, safety and security of a distribution system through the standard control services	6.5.6(a)(4)	We then developed this proposal—relevantly, the operating expenditure forecasts in this document—to meet these customer preferences, and in line with NER requirements to meet reliability, safety and security obligations when providing SCS to our customers. ⁷³

⁷² NER cl. 6.5.6(a).

⁷³ For the purposes of S6.1.2(4) of the NER, we can confirm the objective of our operating expenditure forecast is to maintain existing levels of reliability. Forecast maintenance programs are not designed to improve the performance of JEN under the STPIS.

A1.2 Operating expenditure factors

The NER⁷⁴ set out the factors that the AER must have regards to when deciding whether or not to approve our operating expenditure forecast. Table A1–2 summarises points we consider relevant to these factors.

Table A1–2: Our consideration of the operating expenditure factors

Operating expenditure factor	Rule	Our consideration
[deleted]	6.5.6(e)(1)	n/a
[deleted]	6.5.6(e)(2)	n/a
[deleted]	6.5.6(e)(3)	n/a
The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark operating expenditure by an efficient Distribution Network Service Provider over the regulatory control period	6.5.6(e)(4)	<p>We have carefully reviewed the AER's most recent annual benchmarking report and other relevant measures of benchmark operating expenditure that would be incurred by an efficient distribution network service provider. We fully support the use of benchmarking as useful cross-check information, but not in a deterministic way to set expenditure allowances. In our regulatory proposal, we included the following relevant information concerning benchmarking:</p> <ul style="list-style-type: none"> • Section 4.4.1 summarises our view on the role of benchmarking in assessing the operating expenditure efficiency • Attachment 06-02 <i>Expert opinion on real price escalation</i> evaluates our historical operating expenditure performance and outlines matters to consider when assessing JEN's operating expenditure proposal in the context of the AER's benchmarking reporting.
The actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods	6.5.6(e)(5)	We have included our historical expenditure performance for the current regulatory period in section 2. For earlier regulatory periods, we have reported these in the economic and category analysis benchmarking RINs.
The extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers	6.5.6(e)(5A)	We have proactively engaged with our consumers first to understand the level of service they value (see Attachment 02-01). Our engagement has been industry-leading—gaining industry awards in 2019. We have developed this proposal based on the feedback provided by our customers, and crucially our operating expenditure forecast (together with our capital expenditure forecast) reflects the level of activity required to maintain our current levels of network service throughout the next regulatory period.
The relative prices of operating and capital inputs	6.5.6(e)(6)	<p>We rely on lifecycle management planning for each asset, which considers all strategies and options over the entire asset life from planning to disposal to deliver the lowest sustainable cost over the long run.</p> <p>Lifecycle management focuses on ensuring effectiveness and efficiency in maintenance (operating expenditure) and replacement (capital expenditure) of the network assets based on reliability centred maintenance analysis and considers issues of safety, cost, risk and reliability.</p> <p>Additionally, we relied upon the same input real cost escalators for both operating expenditure and capital expenditure (see section 5.2.1).</p>

⁷⁴ NER cl. 6.5.6(e).

Operating expenditure factor	Rule	Our consideration
The substitution possibilities between operating and capital expenditure	6.5.6(e)(7)	<p>We have considered these opportunities and have proposed optimisation of operating expenditure and capital expenditure under our Future Grid program (see Attachment 05-04 <i>Future grid investment proposal</i>).</p> <p>We also consider substitution possibilities within the regulatory period and may raise these as a part of a demand management incentive scheme.</p>
Whether the operating expenditure forecast is consistent with any incentive schemes or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4	6.5.6(e)(8)	<p>Our ownership model—along with our customers' expectations and the regulatory framework—provides us with strong incentives to act prudently and efficiently when assessing and incurring our expenditure. The two significant schemes that our operating expenditure forecasts consider are the EBSS and the service target performance incentive scheme (STPIS) (see Attachment 07-05 <i>Incentive mechanisms</i>).</p> <p>Note: our operating expenditure forecasts are required to maintain the reliability, quality and security of supply (as per NER clause 6.5.6(a)(3)), and not improve these. As a result, we did not propose any step changes to <i>improve</i> these performance levels.</p>
The extent the operating expenditure forecast is preferable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms	6.5.6(e)(9)	We have established outsourcing arrangements that reflect prudent and efficient commercial terms (see our response to section 28 of schedule 1 in our price reset RIN notice).
Whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b)	6.5.6(e)(9A)	Our proposed operating expenditure forecasts do not include an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b).
The extent the Distribution Network Service Provider has considered and made provision for, efficient and prudent non-network alternatives	6.5.6(e)(10)	We have considered these non-network alternatives, and have made trade-offs between a network and non-network expenditures when developing our Future Grid program (see Attachment 05-04 <i>Future grid investment proposal</i>)
Any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p), or (s)	6.5.6(e)(11)	We publish the final project assessment report reports in our Distribution Annual Planning Report (DAPR) as per 5.17.4(s). We have had regard to the Draft Project Assessment Report when preparing this operating expenditure forecast.
Any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3 is an operating expenditure factor	6.5.6(e)(12)	<p>The Victorian electricity distribution businesses have been in discussion with the AER concerning the change in the regulatory year from a calendar year to a financial year and the consequences of this on this regulatory proposal. In these discussions, approaches to the treatment of operating expenditure for the intervening period and the next regulatory period were outlined. This proposal—and our intervening period proposal⁷⁵—reflect the directions given to us from the AER.</p> <p>There are no other matters which we have been informed of by the AER that we should take into account as an operating expenditure factor.</p>

⁷⁵ JEN, *A proposal for setting electricity distribution service prices, 1 January 2021 to 30 June 2021*, 31 January, 2020.

A1.3 Fixed and variable components

In our building block proposal, we must outline our fixed and variable operating costs.⁷⁶ The NER does not explicitly stipulate a horizon to consider when determining whether a cost is fixed or variable. The forecast horizon of the next regulatory period may be characterised in economic terms as the short run. We adopt this interpretation because over the next regulatory period; we will incur both:

- Variable costs that will change in proportion to customer numbers or as a result of changes to the network's physical capacity
- Fixed costs which by their nature will be incurred regardless of movements in outputs.

These fixed and variable costs may be considered endpoints on a range of cost characteristics. Within this range, we will incur costs that vary on a one-for-one basis with specific outputs as well as costs that will change in a stepped nature. Notwithstanding this, Table A1–3 shows those operating activities for which our costs may broadly be characterised as either variable or fixed by cost category.

Table A1–3: Fixed and variable operating expenditure activities by cost category

Category	Nature of costs	Examples of operating expenditure activities
Corporate overheads	Fixed	<ul style="list-style-type: none"> • executive management • legal and secretariat • human resources • finance • other corporate head office activities
	Variable	<ul style="list-style-type: none"> • N/A
Network overheads	Fixed	<ul style="list-style-type: none"> • management, where not directly related to any of the functions listed below • network planning (i.e. system planning) • network control and operational switching personnel • quality and standards functions including standards & manuals, asset strategy (other than network planning), compliance, quality of supply, reliability, and network records (e.g. Geographic Information Systems) • project governance and related functions including supervision, procurement, works management, logistics and stores • training, OH&S functions, network billing and customer service & call centre • other jurisdictional related expenses • levies
	Variable	<ul style="list-style-type: none"> • GSL payments • demand-side management expenditure or non-network alternatives
Non-network	Fixed	<ul style="list-style-type: none"> • the operation and maintenance of non-network buildings, fittings and fixtures • property costs, including rates, taxed, utilities, etc. • real chattels (e.g. interests in land such as a lease) • IT and communications including replacement, installation, operation, maintenance, licensing, and leasing costs • costs associated with SCADA and network control that exist at the corporate office side of gateway devices (routers, bridges, etc.) • network metering recording and storage at non-network sites (i.e. corporate offices/sites)
	Variable	<ul style="list-style-type: none"> • maintenance and operation of non-network assets, including:

⁷⁶ NER cl S6.12.2(1)(iii).

Category	Nature of costs	Examples of operating expenditure activities
		<ul style="list-style-type: none"> – motor vehicles – non-road registered motor vehicles; non-road motor vehicles (e.g. forklifts, boats etc.) – mobile plant and equipment; tools; trailers (road registered or not) – elevating work platforms not permanently mounted on motor vehicles, and – mobile generators.
Vegetation Management	Fixed	<ul style="list-style-type: none"> • removing, altering, or managing vegetation to maintain safe or regulated clearances from distribution or transmission assets, including tree cutting, undergrowth control, root management, waste disposal, use of herbicide and growth retardants, and encouragement of low-growth vegetation to prevent the establishment of high-growth vegetation • pre-cutting/trimming inspections • inspections of vegetation to ensure that activities have been undertaken appropriately • liaison with affected residents and landowners including the issue of trim/cut notices, and follow up calls on notices, and • operational support, such as any temporary generation used during the activity.
	Variable	<ul style="list-style-type: none"> • To the extent that the electricity network grows, so too will the amount of vegetation management.
Maintenance	Fixed	<ul style="list-style-type: none"> • N/A
	Variable	<ul style="list-style-type: none"> • testing, investigation, validation • preventative and corrective costs not involving capital expenditure • location of underground cables and covering of low voltage mains for safety reasons
Emergency response	Fixed	<ul style="list-style-type: none"> • N/A
	Variable	<ul style="list-style-type: none"> • restore a failed component to an operational state including all expenditure relating to the work incurred where supply has been interrupted or assets damaged or rendered unsafe by a breakdown, making immediate operations and repairs necessary. This occurs primarily due to network failure caused by weather events, vandalism, traffic accidents or other physical interference by non-related entities.

(1) Classification of 'fixed costs' does not mean that these costs will not experience cost escalation over a given period. For example, a fixed activity may involve full-time equivalent (FTE) staff. While the FTE count may be fixed regardless of output growth, we would still reasonably expect to incur cost growth due to wages growth for those FTEs.

Appendix B

Feedback on our draft plan

B1. Feedback on our draft plan

In Table B1–1, we set out the specific feedback we received from customers and stakeholders on our draft plan that relates to our operating expenditure and our responses to this feedback.

Table B1–1: Our responses to customer feedback on operating expenditure

Expenditure category	Topic	Feedback	Our Response
Capital Expenditure Operating Expenditure	Non-network capital and operating expenditure	The Consumer Challenge Panel (CCP) has voiced general concern in relation to growing IT investment across the National Energy Market, especially without transparency of how the money is being spent and what the benefits customers can derive from it are. We were asked to provide details on both capital and operating IT expenditure to provide greater visibility.	Our regulatory proposal demonstrates that our forecast IT capital expenditure is materially below that of our current regulatory period, and counter to the trends exhibited in the NEM. ⁷⁷ We have developed our forecast IT capital expenditure in line with the AER's <i>Non-network ICT capex assessment approach</i> guidance note, which requires network business to demonstrate efficient expenditure. Finally, we take a top-down approach to determining operating expenditure—which includes IT operating expenditure—and we apply a productivity adjustment of 0.5 per cent to ensure cost-efficiency.
Operating Expenditure	Operating expenditure	The ECA concentrated their feedback on JEN's efficiency performance as well as the change to expensing corporate overheads: <ul style="list-style-type: none"> • Efficiencies - whether our proposed base year, set on forecast savings not yet realised was reasonable and whether the proposed step changes and trend in cost escalation could be justified. • Expensing of corporate overheads - what drove the change and whether we would be proposing it if our underlying WACC was not declining. 	JEN has undertaken a review of the operating expenditure and efficiencies and is now proposing CY18 as its base year, which alleviates concerns about whether the expected efficiencies in CY19 have come through even though the year is not yet finalised. The change in the treatment of corporate overheads has been driven by the changing nature of our actual costs incurred, more of which are now short-term in nature rather than long-term. For example, more and more IT costs are now charged on an annual license fee basis, rather than relating to the purchase of equipment.
		The ECA (supported by Spencer and Co.) also questioned the productivity escalator we used in our draft plan, stating that JEN should commit to using it rather than the lower figure determined by the AER.	At the time of developing our draft plan, the AER's work on determining the productivity factor was not complete. Since then, the AER completed its work and determined a productivity factor of 0.5 per cent per annum. JEN considers that to apply an even higher productivity factor than that determined by the AER would not be a reflection of efficient costs.
Operating Expenditure	Customers	The response from our People's Panel indicated we had achieved	The selection process we employed to recruit our People's Panel members ensured

⁷⁷ NER cl S6.12.2(1)(iii).

Expenditure category	Topic	Feedback	Our Response
		<p>the right balance between Affordability, Reliability and Sustainability.</p> <p>They also asked us to engage further with both vulnerable and culturally and linguistically diverse (CALD) customers to help with energy literacy and overall understanding. Our Customer Council also recommended that further consideration of vulnerable and CALD customers was needed, especially concerning affordability.</p>	<p>representatives across the diverse demographics of JEN's distribution area were included, including CALD customers. Through this process, we heard that the cost of electricity puts significant pressure on their cost of living and we are committed to continuing to find efficiencies and deliver value including as contributors to the National Energy Charter and tariff reform plans of the Victorian distribution businesses.</p>
		<p>Our People's Panel suggested it would strengthen our plan to provide incentives for households to invest in renewable energy.</p>	<p>We actively share the recommendations and views expressed by the People's Panel to regulators, rule makers and the wider industry to highlight the changing and growing desire of the community to have an energy system that supports an increasingly renewable future.</p>
		<p>The ECA questioned our proposed customer service incentive and were concerned that customers might pay twice for the same outcomes.</p>	<p>We have consulted with our People's Panel on the Customer Service Incentive Scheme, and they were also not supportive of it. As a result, we will not be proposing to include it in our regulatory proposal.</p>
		<p>The Customer Council also queried how customer investments and behaviour behind the meter (for example, solar and battery installations, electric vehicle charging) are likely to impact the nature of pricing and customers without these technologies.</p>	<p>Existing and emerging market developments mean that customers' usage profiles are diverging over time. Today and in future, customers are driving changes that are affecting peak demand through:</p> <ul style="list-style-type: none"> • Continued growth in air-conditioner load, exacerbating the early evening peak • The emergence of electric vehicles which could exacerbate the early evening peak. • Future take-up of home batteries with solar PV effectively allowing a solar generation to be shifted to any period. • Continued new connections are driven by state population growth. <p>Our operating expenditure forecast also incorporates our Future Grid program (see Attachment 05-04) which leverages a range of technologies and capabilities to better manage the low voltage network because of the growing behind-the-meter developments and increased two-way power flows on our network.</p>

Appendix C

Overview of operating expenditure categories

C1. Overview of operating expenditure categories

Below we outline the categories of expenditure and list the types of costs we incur under each category.

C1.1 Vegetation Management

Vegetation management expenditure covers activities that:

- are primarily directed at removing, altering, or managing vegetation to maintain safe or regulated clearances from distribution or transmission assets
- are not emergency or fault related activities
- are not initiated by request from a distribution or transmission customer, excluding customers that are network service providers
- are not activities for which expenditure could be attributed to the AER expenditure category 'Augmentation, replacement, or non-routine maintenance activities triggered by a changed regulatory obligation or requirement
- are not activities for which expenditure could be attributed to the AER expenditure category 'Augmentation, replacement, or non-routine maintenance activities triggered by a changed internal standard'
- include tree cutting, undergrowth control, root management, waste disposal, use of herbicide and growth retardants, and encouragement of low-growth vegetation to prevent the establishment of high-growth vegetation.

This includes:

- pre-cutting/trimming inspections
- inspections of vegetation to ensure that activities have been undertaken appropriately
- liaison with affected residents and landowners including the issue of trim/cut notices, and follow up calls on notices, and
- operational support, such as any temporary generation used during the activity.

This does not include:

- such items as "beautification" works, lawn mowing, e.g. from nature strips, or office gardens, interior plant and aesthetic vegetation works, and
- any work which is done in proximity to non-network assets.

C1.2 Maintenance

Operational repairs and maintenance of the distribution system including high-voltage and low-voltage assets, and including testing, investigation, validation and correction costs not involving capital expenditure. This also includes the location of underground cables and covering of low voltage mains for safety reasons.

C1.3 Emergency response

Operating costs incurred to restore a failed component to an operational state including all expenditure relating to the work incurred where supply has been interrupted or assets damaged or rendered unsafe by a breakdown, making immediate operations and repairs necessary.

Costs of activities primarily directed at maintaining network functionality and for which immediate rectification is necessary. These activities are mostly due to network failure caused by weather events, vandalism, traffic accidents or other physical interference by non-related entities.

C1.4 Non-Network

Expenditure that is directly attributable to non-network buildings and property assets including the replacement, installation, operation and maintenance of buildings, fittings and fixtures. It includes expenditure related to real chattels (e.g. interests in land such as a lease) but excludes expenditure related personal chattels (e.g. furniture) that should be reported under non-network other expenditure.

All non-network expenditure directly attributable to IT and communications assets including replacement, installation, operation, maintenance, licensing, and leasing costs but excluding all expenses associated to SCADA and network control expenditure that exist beyond gateway devices (routers, bridges etc.) at corporate offices.

IT & communications expenditure includes:

- costs associated with SCADA and network control that exist at the corporate office side of gateway devices (routers, bridges, etc.). For example, this would include cost associated with SCADA master systems/control room and directly related equipment
- IT & communications expenditure related to management, dispatching and coordination, etc. of network work crews (e.g. phones, radios etc.)
- any common costs shared between the SCADA and network control expenditure and IT & communications expenditure categories with no dominant driver related to either of these expenditure categories. For example, a dedicated communications link used for both corporate office communications and network data communications with no dominant driver for incurring the expenditure attributable to either expenditure category should be reported as IT & communications expenditure
- expenditure related to network metering recording and storage at non-network sites (i.e. corporate offices/sites).

All expenditure directly attributable to the replacement, installation, maintenance and operation of non-network assets, excluding motor vehicle assets, building and property assets and IT and communications assets and includes:

- non-road registered motor vehicles; non-road motor vehicles (e.g. forklifts, boats etc.)
- mobile plant and equipment; tools; trailers (road registered or not)
- elevating work platforms not permanently mounted on motor vehicles
- mobile generators.

C1.5 Network Overheads

Network overhead costs refer to the provision of network, control and management services that cannot be directly identified with specific operational activity (such as routine maintenance, vegetation management, etc.).

For a DNSP, network overheads may include the following:

- Management, where not directly related to any of the functions listed below
- network planning (i.e. system planning)
- network control and operational switching personnel
- quality and standards functions including standards & manuals, asset strategy (other than network planning), compliance, quality of supply, reliability, and network records (e.g. geographical information systems (**GIS**))

- project governance and related functions including supervision, procurement, works management, logistics and stores
- other including training, OH&S functions, network billing and customer service & call centre.

In addition to the above, network overhead may include:

- advertising and marketing
- GSL payments
- Other jurisdictional related expenses
- demand-side management expenditure or non-network alternatives, and
- levies.

C1.6 Corporate Overheads

Corporate overhead costs refer to the provision of corporate support and management services by the corporate office that cannot be directly identified with specific operational activity. Corporate overhead costs typically include those for executive management, legal and secretariat, human resources, finance, and other corporate head office activities or departments

