Jemena Electricity Networks (Vic) Ltd

2021-26 Electricity Distribution Price Review

Attachment 05-01

Response to the AER's draft decision - Operating expenditure

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Glossary

current regulatory period	The regulatory control period covering 1 January 2016 to 31 December 2020
draft decision	The draft decision on the determination that will apply to setting JEN's distribution prices for the next regulatory period
initial proposal	The initial regulatory proposal to the AER for the setting of regulated pricing for JEN for the next regulatory period
intervening period	The regulatory period covering 1 January 2021 to 30 June 2021
next regulatory period	The regulatory control period covering 1 July 2021 to 30 June 2026
revised proposal	The revised regulatory proposal to the AER for the setting of regulated pricing for JEN for the next regulatory period
standard control services	The electricity distribution services provided using JEN's shared electricity network. Per the NER definition, a standard control service is a direct control service that is subject to a control mechanism based on a DNSP's total revenue requirement
updated proposal	Following the submission of our initial proposal (but before the draft decision), we lodged an updated regulatory proposal for the next regulatory period which adjusted the base year operating expenditure amount

Abbreviations

ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
BIS	BIS Oxford
CAM	Cost Allocation Methodology
CA RIN	Category Analysis Regulatory Information Notice
CESS	Capital Expenditure Sharing Scheme
CY	Calendar Year
DAE	Deloitte Access Economics
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
DRC	Debt Raising Costs
EBSS	Efficiency Benefit Sharing Scheme
EDC	Electricity Distribution Code (Victoria)
ESCV	Essential Services Commission of Victoria
ESV	Energy Safe Victoria
FY	Financial Year[1]
GSL	Guaranteed Service Level
LSE TL	Least Squares Econometric Transcendental Logarithm
MTFP	Multilateral Total Factor Productivity
NER	National Electricity Rules
NSW	New South Wales
OEF	Operating Environment Factor
REFCL	Rapid Earth Fault Current Limiter
RIN	Regulatory Information Notice
SFA TL	Stochastic Frontier Analysis Transcendental Logarithm

1 When expressing the financial year, we follow the initials with a two year digit code. The two digits represent the latest year that straddled the annual period. For example, the financial year 1 July 2021 to 30 Jun 2022 is represented as FY22.

Overview

The operating expenditure outlined in this document reflects the costs Jemena Electricity Networks (Vic) Ltd. (**JEN**) require to fund its everyday operations when providing standard control services to our customers over the 2021–26 regulatory control period (**next regulatory period**). It is a revision (**revised proposal**) to the allowance we sought in our 2021-26 initial regulatory proposal (**initial proposal**) and is made in response to the Australian Energy Regulator's (**AER**'s) 2021–26 draft decision (**draft decision**) for JEN.

After lodging our initial proposal, we offered an updated operating expenditure allowance for the next regulatory period (**updated proposal**) to account for a downward adjustment to our base year operating expenditure amount.[2] However, the AER's draft decision alternative operating expenditure forecast of $500 million (including debt raising costs (**DRC**)) is significantly (10.6%) lower than the operating expenditure we proposed in our updated proposal.

Table OV–1 outlines the operating expenditure allowance we sought in our initial proposal, the updates we made to the AER in our updated proposal, the AER's draft decision, and our revised proposal amount.

Table OV–1: Operating expenditure summary ($2021 $M)

	Initial proposal	Updated proposal	Draft decision	Revised proposal	Difference (IP to RP)
Total operating expenditure (incl. DRC)	576.6	559.3	499.8	532.3	-44.3

We are concerned by the AER's draft decision to reject our operating expenditure proposal for the next regulatory period. Our response explains why the AER should reconsider its draft decision on our operating expenditure.[3]

Customer impacts

What this means for our customers

- When speaking to our customers, they told us affordability was important to them,[4] however, they also recognised how critical it is that we provide a reliable and sustainable electricity distribution service over the long term. In effect, our customers told us to find balance in the things we do and the costs we incur to do them, not only now, but also over the long term.
- Based on this, we consider that customers' long term interests are best served when the allowances for operating expenditure are set at efficient levels. If set too:
  - high, then customers will pay more for their standard control services than they should
  - low, then network business will not be able to provide standard control services sustainably over the long term
- Customers' long term interests are also best served when a DNSP is given a balanced set of incentive schemes which ensure efficient trade-offs between capital expenditure, operating expenditure and service levels.
- In this revised proposal, we seek an operating expenditure allowance of $532.3M, which is 7.7% lower than the amount in our initial proposal. We also demonstrate why it is efficient for us to have an operating expenditure allowance of 6.5% above the amount in the AER's draft decision amount to meet the long term interests of our customers.

2 JEN provided an updated proposal to the AER during information request '*JEN - Response to AER IR052 - 27 July 2020*' with lower operating expenditure to pass on the expected savings from our transformation program to customers earlier than the default operation of the regulatory framework.

3 Unless stated otherwise or the context indicates, all financial values included in this attachment are in dollars as at 30 June 2021, which is defined as '$2021'

4 JEN, *2021-26 Electricity Distribution Price Review, Regulatory Proposal, Attachment 02-02, Community engagement report*, Pg. 43.

- By transparently outlining the reasons for seeking the revised proposal operating expenditure allowance, our customers can be confident that we have struck the right balance to deliver the services at an efficient operating cost expected of us.

Response to the draft decision

In developing operating expenditure forecasts, we have adopted the AER's preferred base, step and trend approach. A summary of the key decision items in the AER's draft decision and our response to each of these is outlined in Table OV–2.

Table OV–2: Description of the draft decision

Key decision items	AER position	JEN response
Base year		
Selection of the base year	The AER accepted the use of CY18 as an appropriate base year.	**Accept**
Efficiency adjustment to base year operating expenditure	The AER applied a 15% adjustment to JEN's base year operating expenditure based on its benchmarking analysis.	**Reject** – Our analysis shows that no efficiency adjustment is required on our revised proposal operating expenditure, which includes a negative step change of $4 million per annum that was not included in our initial proposal, to pass on expected savings from our CY19 transformation program. We have significant concerns with the economic benchmarking analysis that the AER used to justify its 15% adjustment. Both our and CEPA's[5] analysis shows that once the impact of capitalisation practices across businesses and reliability of model results are considered, JEN's efficiency score materially improves and its base year proposal can be used for setting its operating expenditure allowance for the next regulatory period.[6] We are also concerned that the top-down benchmarking analysis has been deterministically applied in the draft decision despite its imprecision. Recent errors with the Multilateral Total Factor Productivity (**MTFP**), for instance, are an important reminder that such modelling is prone to error, assumption, and methodology choices that mean the modelled outcomes are subjective. Although tempting to assume modelled outputs accurately reflect the level of relative efficiency, operating and financial accounting practices vary across Distribution Network Service Providers (**DNSP**s). Accordingly raw benchmarking outcomes cannot be relied upon to provide a full indication of efficiency level. Due consideration needs to be given to

5 CEPA's report is provided in Attachment 05-05.

6 Throughout this attachment we use 'capitalisation practices' as the combined impact of operating expenditure/capital expenditure trade-offs and capitalisation policies on the level of capitalisation (to align with the AER's definition in the draft decision). We use 'capitalisation policies' to refer to individual DNSP choices on whether to treat a given type of expenditure as either operating expenditure and/or capital expenditure, which excludes operating expenditure/capital expenditure trade-offs.

Key decision items	AER position	JEN response
		the impacts of differences in capitalisation practices across businesses when interpreting and relying on the model results. We recommend that the AER at the very least apply an operating environment factor (**OEF**) for JEN to take into account the impact of capitalisation differences on JEN's efficiency score and not apply translog model results to JEN due to statistical and other issues. This will demonstrate that our revised proposal provides a prudent and efficient basis to set operating expenditure allowance for the next regulatory period.
Efficiency adjustment to newly expensed corporate overheads	The AER applied a 15% adjustment to JEN's newly expensed corporate overheads	**Reject** – The base year operating expenditure efficiency adjustment should not be applied to the newly expensed corporate overheads. This is because these costs represent a movement from capital expenditure to operating expenditure, and are not costs that were in the reported base year operating expenditure used for the AER's efficiency assessment.
Final year increment	The AER accepted a final year increment that is $0.6 million ($2021) (or $3 million ($2021) over the next regulatory period) lower than JEN proposed due to an updated inflation estimate and by adopting an average of capitalised corporate overheads from 2016 to 2018.	**Accept**
Trending of base year		
Input cost trend	The AER used labour price growth based on a forecast it obtained from Deloitte Access Economics (**DAE**) rather than its standard approach of averaging two forecasts (BIS Oxford (**BIS**) and DAE). The AER cited that only the DAE forecast factors in the impacts of COVID-19, and that its final decision will revisit this approach based on more current information. The AER has accounted for the legislated superannuation guarantee increases in the DAE forecast. The AER also reduced the cost input weight applied to labour.	**Partially accept** – JEN's revised operating expenditure forecast reflects the AER's past practice of relying on more than one expert forecaster where available. JEN has provided updated forecasts from BIS that account for the impacts of COVID-19 and the increase in superannuation guarantee which we have then averaged with the AER's DAE forecast. JEN retains the AER's draft decision labour weight in the revised proposal but recommends the AER rely on a more recent industry average labour weight by using the 2015–19 average instead of the 2014–16 average used in the draft decision.
Output growth trend	The AER relied on output weights from the MTFP and the four econometric models using 2018 data. The output weights for transcendental logarithm (i.e. translog) models are based on an Australian sample mean instead of the AER's past practice of international sample mean.	**Partially accept** – Although JEN has concerns with using MTFP and translog models due to their statistical issues. JEN's revised operating expenditure forecast retains the AER's standard approach of averaging across all five models. JEN recommends that the AER review the reliability and reasonableness of the output weights from

Key decision items	AER position	JEN response
	The AER stated that it will update the output weights according to the 2020 benchmarking report in its final decision. The AER also updated JEN's forecast on: • customer numbers to reflect project dwelling growth in light of the COVID-19 pandemic • ratcheted maximum demand based on AEMO's November 2019 transmission point connection forecast • energy throughput to reflect the historical average growth rate for 2006–18.	MTFP and translog models before applying them to the operating expenditure forecast in its final decision. JEN accepts the AER's output growth rates on customer numbers, circuit length and ratcheted maximum demand. However, we have: • incorporated updated customer numbers from our restated Economic Benchmarking Regulatory Information Notice (**RIN**) response and retains the growth rate from the AER's draft decision • updated the energy throughput forecasts that reflect the most recent 5-year average growth rate from the 2015–19 period.
Productivity	The AER applied a 0.37% productivity rate in 2021-22 to reflect 9 months of escalation then 0.5% productivity rate per year for each subsequent year of the next regulatory period. This is consistent with its standard approach and its operating expenditure forecast for the six-month regulatory period between the current regulatory period and the next regulatory period (**intervening period**).	**Accept**
Specific forecasts		
Guaranteed service level (**GSL**) payments	The AER approved a slightly higher forecast than JEN proposed because it adopted the historical average of JEN's annual payments from 2015 to 2019. This compared to JEN's proposal which had relied upon actual payments in the 2018 base year. The AER noted that the final decision may require updating for the outcome of a current review of the Victorian GSL scheme.	**Accept** – JEN has reviewed the final decision on the Electricity Distribution Code (**EDC**) and our analysis shows that although the payment and volume of payments are both expected to increase, the overall increase in costs is likely to be immaterial. JEN considers that it can manage the increase in GSL costs within the allowance outlined in the draft decision.
Electricity Levy for Energy Safe Victoria (**ESV**)	The AER acknowledges that this levy has increased and is not within the Victorian networks' ability to control. Yet it did not provide any additional funding for this nor did it agree to the alternative of using the existing B factor term in the price control mechanism for standard control services.	**Reject** – These are actual and unavoidable cost increases over which JEN has no control. They are efficiently incurred in line with JEN's licence obligations and it is incorrect to overlay an "exceptional circumstances"[7] test to efficient cost recovery during a price review. These must be funded either as a specific forecast or an annual pricing adjustment. JEN proposes to include this ESV levy in the specific forecast.
Step changes		
Bushfire Insurance Premium	The AER approved $28 million as proposed (with updates for the AER's inflation forecast).	**Accept**
Rapid earth fault current limiter	The AER approved $1 million as proposed (with a qualification that JEN will update its revised	**Partially accept** – JEN has retained the step change accepted by the AER, however,

7 AER, *Attachment 6: Operating expenditure | Draft decision – Jemena 2021–26*, Pg. 6-75

Key decision items	AER position	JEN response
(**REFCL**) testing & maintenance	forecast for inflation and the outcome of our requested exemption.	updated it to reflect more recent cost estimates and inflation forecast.
Cyber-security	The AER approved $3 million as proposed.	**Accept**
Future Grid program	The AER rejected this $4 million step change.	**Accept**
Transitional return on debt alignment costs	The AER accepted JEN's withdrawal of this $0.9 million step change.	**Accept**
Environment Protection Act changes	The AER rejected this $4 million step change.	**Accept**
Additional regulatory information notice RIN reporting	The AER rejected this $0.5 million step change.	**Accept**
Other operating expenditure items		
DRC	The AER applied its standard calculation approach and assumptions to determine allowed DRC.	**Accept**

Developments since submitting our initial proposal

Since lodging our initial proposal, several changes have arisen that impact our revised proposal. We are raising these new issues for inclusion in the AER's final decision. The changes include:

- **Changes to the National Electricity Rules (NER) may affect the scope of services** – The Australian Energy Market Commission (**AEMC**) is considering a suite of NER changes that will affect the scope of JEN's distribution services. These are being considered collectively in its review titled: '*Distributed energy resources integration – updating regulatory arrangements*'. We have not reflected any subsequent changes into our revised proposal operating expenditure forecast given a draft decision from the AEMC is not expected until March 2021. However, the final rule change:
  - will be of direct consequence to the output measures that should be used to forecast output growth and assess our efficiency performance – which supports our position (discussed in section 3.1.2.1) that customer numbers are a more appropriate driver of operating expenditure than ratcheted maximum demand; and
  - may impose regulatory obligations on JEN that result in positive step changes over the next regulatory period.
- **Changes to the Victorian EDC** – A broad range of amendments to the EDC will impact JEN's services and costs during the next regulatory period. (Note: changes to GSL scheme under the EDC are not expected to have a material impact, and therefore, we have not reflected these changes in our revised specific forecast).
- **Exemption for Coolaroo zone substation** – JEN has been granted an exemption which will allow us to meet bushfire mitigation (REFCL) obligations at the Coolaroo zone substation for a lower cost than we otherwise would have to incur. We have reflected this in our revised proposal step change forecast, in addition to the costs of addressing similar requirements in relation to the Kalkallo zone substation.

Additional information

Additional information supporting JEN's positions is outlined in Table OV–3.

Table OV–3: Additional documents supporting this submission

Document reference	Document details
Attachment 05-01M	JEN – 05-01M SCS Opex Model FY22-26 – 20201203 – Public
Attachment 06-01M	JEN – 06-01M EBSS Model – 20201203 – Public
Attachment 05-02	BIS Oxford – Labour cost escalation forecasts
Attachment 05-03	BIS Oxford – Note on Changes to AER Treatment of Inflation
Attachment 05-04	Jemena Insurance Report 2020 – 20201203 – Confidential
Attachment 05-05	CEPA – The AER's opex benchmarking – a review of the impact of capitalisation and model reliability – 20201203 – Public
Attachment 05-06	JEN – REFCL step change estimate – 20201203 – Public
Attachment 05-07	JEN – Benchmarking Analysis – 20201203 – Public

1. Revised proposal operating expenditure forecast

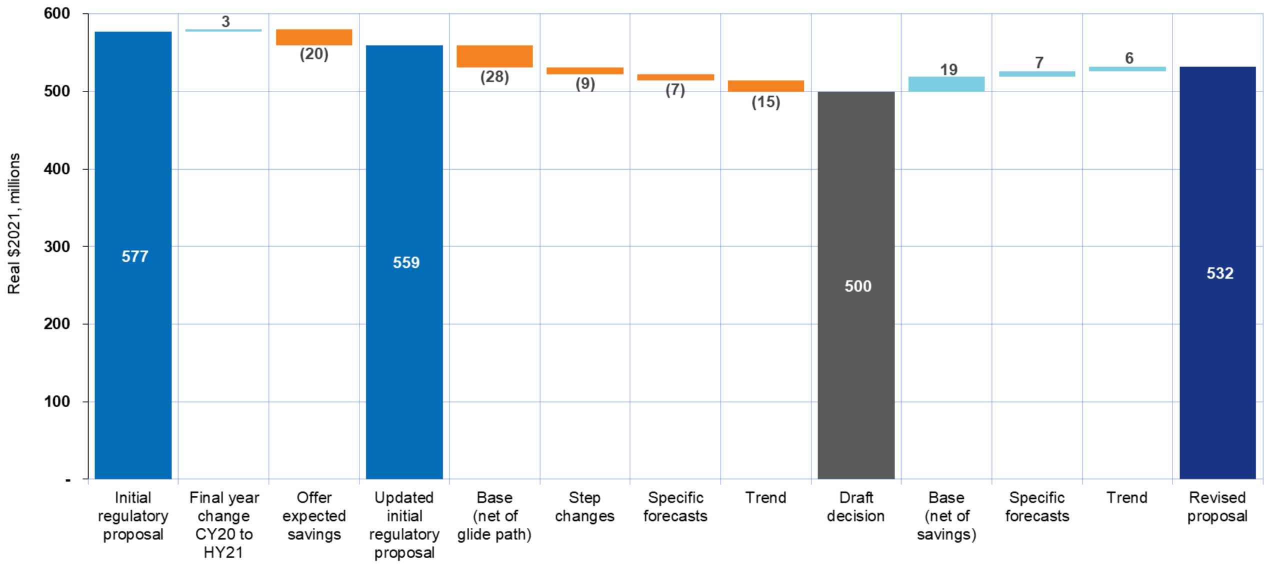
Our revised forecast operating expenditure (including DRC) for the next regulatory period is $532 million, which is approximately $33 million higher than the AER's draft decision and $27 million lower than our updated proposal.

Table 1–1 provides a comparison of JEN's proposed operating expenditure with the AER's draft decision. Figure 1–1 illustrates the changes from JEN's initial proposal through to the draft decision and our revised proposal.

Table 1–1: Summary of the revised proposal operating expenditure ($2021 $M)

	Initial proposal	Updated proposal	Draft decision	Revised proposal	Difference (RP to DD)
			[1]	[2]	[2] - [1]
Base (actual operating expenditure in 2018)	427.8	427.8	422.5	422.5	-
Adjustment to final year (incl. newly expensed overheads)	67.9	76.8	78.3	72.7	(5.7)
Pass on expected transformation program savings	-	(20.2)	-	(20.0)	(20.0)
Efficiency adjustment net of glide path	-	-	(44.9)	-	44.9
Trend - output growth	23.6	20.0	11.8	14.0	2.3
Trend - real price growth	10.8	9.4	0.9	6.1	5.2
Trend - productivity	(8.0)	(8.1)	(6.0)	(7.1)	(1.1)
Step changes	42.4	41.5	32.4	32.4	0.1
Category specific forecasts	7.8	7.8	0.9	7.8	6.8
DRC	4.4	4.4	4.0	4.0	0.02
Total operating expenditure (incl. DRC)	**576.6**	**559.3**	**499.8**	**532.3**	**32.5**
Revised proposal percentage difference to the draft decision					6.5%
Revised proposal percentage difference to the initial proposal					(7.7%)
Revised proposal percentage difference to updated proposal					(4.8%)

Figure 1–1: Operating expenditure changes from initial proposal through to draft decision and revised proposal ($2021 $M, incl. DRC)



Our revised proposal operating expenditure forecast reflects:

- the AER's draft decision to accept 2018 as the base year. Although we have not applied the AER's efficiency adjustment, we have included a $4 million negative step change per year for projected efficiency gains from our transformation program
- our proposed methodology for forecasting input cost growth, which is the AER's standard practice of averaging two available forecasts factoring in COVID-19 impacts, and the increase in the superannuation guarantee
- our revised energy throughput forecast which is used to forecast output growth
- updated specific forecasts for increased ESV levies, which the draft decision acknowledged were an unavoidable cost
- the AER's draft decision on allowed DRC,[8] and
- the AER's draft decision on step changes with updated forecast for the REFCL testing & maintenance step change to reflect the current status of our exemptions and compliance requirements administered by ESV.

The following sections provide more detail on our revised proposal positions.

8 JEN applied the method and input assumptions used by the AER in its draft decision.

2. Base year operating expenditure position

AER's draft decision

The AER draft decision rejected the use of our proposed base year revealed operating expenditure for setting allowances. The draft decision deemed our base year operating expenditure to be materially inefficient and applied a 15% efficiency adjustment.

This adjustment:

- was deterministically derived from the AER's econometric modelling of estimated efficient operating expenditure and was combined with a glide path allowance over the next regulatory period. The AER applied a step change to provide a transition path for JEN to reach the AER's estimate of efficient operating expenditure by the last year of the next regulatory period;
- reduced the base operating expenditure forecast by $45 million ($2021) over five years net of the glide path step change; and
- was $25 million ($2021) lower over five years than our updated proposal which included a $20 million proactive negative step change to immediately pass on the expected savings to customers from our 2019 transformation program.[9]

The AER draft decision accepted:

- the 2018 calendar year as an appropriate base year, and
- the average of 2016 to 2018 values for estimating the capitalised corporate overheads to be expensed over the next regulatory period.

Issues with the AER's benchmarking assessment

It is unreasonable to conclude that our 2018 operating expenditure is materially inefficient and apply a 15% reduction based on top-down economic benchmarking models which:

- do not adequately capture factors that impact the comparability of benchmarking results, and
- are prone to statistical issues.

Our key concerns with the AER's current benchmarking assessment approach are:

- **It does not account for differences in capitalisation policies,** which limits the comparability of benchmarking results (section 2.1.1). The AER's benchmarking analysis relies on cost data consistent with how each business capitalised costs back in 2014. This analysis does not take into account capitalisation differences between businesses or how capitalisation policies have changed since 2014, as some businesses changed their Cost Allocation Methodologies (**CAMs**).

  These capitalisation differences have a material impact on JEN's benchmarking performance. This is illustrated by CEPA's analysis[10] which found that JEN's efficiency score is significantly higher (15%-17%) if the current (2019) CAMs are used (i.e. backcast 2019 CAMs to historical years).

  The AER concluded in its draft decision that no adjustment for capitalisation differences is required as the ratio between JEN's operating expenditure and total expenditure ratio is similar to the average of the frontier DNSPs operating under the 2014 CAMs.

9 This negative step change of $4 million per annum over the next regulatory period was included with updates made to our initial proposal prior to the draft decision.

10 CEPA, *The Australian Energy Regulator's operating expenditure benchmarking – a review of the impact of capitalisation and model reliability*, 13 November 2020, p. 15-18.

However, CEPA found that the ratios – and especially operating expenditure to total expenditure – do not provide adequate information on capitalisation differences as intended by the AER. This is because high-level ratios can capture differences irrelevant to the operating expenditure efficiency assessment such as the position in the asset replacement cycle, and augmentation and safety requirements.

If the AER continues to rely on benchmarking results based on DNSPs' 2014 CAMs, CEPA considers it appropriate to include a positive OEF for JEN to account for differences in capitalisation (as captured in its 2019 CAM). CEPA also recommends that the AER do not rely on simple ratios without properly understanding any capital expenditure differences as they can mask material differences in capitalisation policies amongst DNSPs, and therefore, the operating expenditure efficiency assessment.

- **It relies on translog models that are prone to significant statistical issues** (section 2.1.2). The AER takes the average of four models in the long sample period (2006–19) and four models in the short sample period (2012–19) in its assessment of DNSPs' benchmarking performance.

  As the monotonicity violations[11] on both SFA TL and LSE TL models become more prevalent in 2020 (based on 2019 dataset) , the available models for JEN (without monotonicity violations) lowers to two in the short sample and three in the long sample.

  The only translog model without monotonicity violation for JEN, the LSE TL, gives unreasonably low results compared to all other available models. As a result this outlier model now carries more weight in the average as there are only five available models for JEN. This significantly increases the risk of including an inappropriate model in the AER's operating expenditure assessment.

  CEPA recommends the AER should critically investigate the discrepancy before applying it in the operating expenditure assessment for JEN, on the ground of no monotonicity violation.

- **It includes a vegetation management OEF based on regulatory allowances rather than revealed actual costs** (section 2.1.3). In its draft decision, the AER included a negative OEF for JEN to account for its relatively low vegetation management regulatory obligation costs compared to other Victorian DNSPs. This OEF is determined using historical allowances set in 2010 rather than actual costs, which is inconsistent with how other OEFs are determined and with benchmarking models that rely on actual historical data and not allowances.

  We understand that the AER's use of regulatory allowance data is due to a lack of available actual RIN data. A cross-check using actuals from the Category Analysis (**CA**) RIN is available and our analysis suggests that the allowance and actuals are closely aligned for all Victorian DNSPs except for CitiPower.

  Adjusting the OEF with actual data for Victorian DNSPs results in a slightly smaller negative OEF for JEN. We recommend the AER collects actual data for CitiPower for the years 2006-10 to satisfy itself that the results are not significantly different from using allowances for this purpose. Otherwise, JEN's operating expenditure allowance is being negatively adjusted without a reasonable basis.

Later in this document, we further explain each concern and outline an approach to adjust for the operating expenditure efficiency assessment.

As outlined in the CEPA report and the summary chart in section 2.1.4, adjustments for these issues will see our base operating expenditure—after factoring in the $4 million annual transformation benefit (i.e. negative step change)— is efficient when compared to the benchmark efficient operating expenditure.

Ultimately, we are concerned that economic benchmarking was applied deterministically in the draft decision to JEN's detriment. In our view, it should not apply deterministically unless:

- detailed bottom-up analysis of costs (including capital expenditure) is first used to understand the differences between the DNSPs

11 Monotonicity violations occur when the model indicates that an increase in output does not increase costs. When monotonicity violations occur it indicates that there are issues with the model and raises the question of whether the estimates can be relied upon. Economic Insights and the AER exclude those econometric models which have violations for more than half a DNSP's observations in their benchmarking assessment.

- differences in capitalisation and other accounting policies of other DNSPs are normalised, and
- benchmarking results are sensible, robust, and not volatile irrespective of the choice of output weights—especially where these output weights are not determined in a statistically robust manner.

The errors identified with the MTFP model output weights in the 2020 draft benchmarking report raises broader concerns, especially given their material effect on the ranking of businesses. These errors should not be taken lightly. If anything, these errors highlight–to all stakeholders–why the economic benchmarking techniques in their current state should not be applied deterministically.

Given the time since the AER first started relying on economic benchmarking in its regulatory decisions, we also recommend that it undertake an overall health check of its benchmarking tools and practice. It should, for instance, seek refreshed views by experts other than Economic Insights to ensure that these tools and practices are working in the long-term interests of customers. Broadening the scope of experts into the AER's analysis on benchmarking would be similar to the AER's recent engagement of the Brattle Group to obtain new perspectives on the rate of return.

Our commitment to passing on expected efficiency improvements

Our concerns with the AER's current benchmarking approach are all the more important when compared to the base year operating expenditure adjustments we included in our updated proposal.

Our updated proposal included measures to proactively share future expected cost efficiencies—worth $4 million per annum—with our customers. We do this by returning the benefits of our transformation program faster than would normally occur under the AER's standard approach where benefits are shared through the EBSS mechanism and thus lagged by a regulatory control period before being received by our customers.

Our proposed reduction is based on achievable management initiatives to lower our operating expenditure (that are already 12% below our allowance)[12] while maintaining the safety and reliability standards our customers expect. This contrasts to the theoretical desktop modelling the AER relied upon in its draft decision, which:

- cannot be assumed to sustain our efficient, safe, and reliable operations because it is based on theoretical and imprecise economic modelling and
- cannot be used to conclude our forecasts are materially inefficient once the modelling issues we have raised are accounted for, and once our proactive negative step change is also considered.

Revised proposal

Our revised proposal base year operating expenditure forecast inputs are set out in Table 2–1. We maintain our position in the updated proposal to offer a $4 million per annum negative step change and make *no* efficiency adjustment to the base year operating expenditure.

Over the next regulatory period, our revised proposal base year operating expenditure is $19 million higher than the draft decision, $21 million lower than our initial proposal, and $9 million lower than our updated proposal.

Table 2–1: Summary of the revised proposal base operating expenditure ($2021 $M)

	Initial proposal	Updated proposal	Draft decision	Revised proposal
Base year operating expenditure	427.8	427.8	422.5	422.5
Expensing corporate overheads	62.1	62.1	59.0	59.0
Items forecast using specific forecast	(6.7)	(6.9)	(0.9)	(6.5)

[12] This is based on comparing our actual standard control services operating expenditure in 2018, of $81.8 million ($Nominal) or $78.4 million ($2015), to our allowed operating expenditure for 2018, of $89.0 million ($2015) with DRC.

	Initial proposal	Updated proposal	Draft decision	Revised proposal
Final year increment[13]	12.5	21.6	20.2	20.2
Efficiency adjustment (net of glide path)	-	-	(44.9)	-
Proactive negative step change (expected transformation program savings)	-	(20)	-	(20)
Adjusted base	**495.6**	**484.4**	**455.9**	**475.1**

2.1 Economic benchmarking

In assessing JEN's base year efficiency, the draft decision applied the benchmarking results in a deterministic manner for. We appreciate that the AER has used a glide path to assist JEN in reaching this target. However, we consider that this decision needs to be informed by a broader range of additional factors that impact JEN's benchmarking results.

These factors have a material impact when assessing JEN's operating expenditure base year efficiency. The AER must ensure that the final decision is based on a comprehensive evaluation of JEN's efficiency that accounts for these factors. Without due consideration of these additional factors, the AER's decision could have an adverse impact on our operations and service levels and therefore our customers' experience.

The following sections discuss issues with the AER's current benchmarking approach and how we propose to account for these – namely, differences in capitalisation policies, reliability of translog models, OEF on vegetation management obligations, and the reliability of the MTFP model.

2.1.1 Capitalisation differences materially affect results and must be accounted for

In our view, capitalisation differences materially affect the reliability of benchmarking results. Our expert economist, CEPA, calculates that accounting for this difference materially improves JEN's operating expenditure benchmarking efficiency score by 15% to 17%. We explain this below with additional detail provided at Attachment 05-05.

The AER's operating expenditure economic benchmarking does not account for differences in capitalisation practices applied by other DNSPs. The AER recognises this potential issue in its draft 2020 benchmarking report – noting that differences in capitalisation practices may materially impact the comparability of operating expenditure benchmarking results[14]. The AER states that it intends to consult on this issue during 2021[15].

We agree consultation is important and must occur prior to any reliance on the benchmarking results. This is especially important when considering the efficiency of JEN's base year operating expenditure. Applying the benchmarking results deterministically before the findings of the benchmarking investigation are made could see JEN receive a base year allowance lower than it ought to.

In its draft decision, the AER undertook a preliminary investigation into this issue. It did so by:

- **characterising** 'capitalisation practices' as including both operating expenditure/capital expenditure trade-offs (i.e. choices over what to spend on) and capitalisation policies (i.e. choices over how to treat a given expenditure); and

13 The 'final year' in our initial proposal is defined as CY2020. During the information request process, the AER provided an alternative approach to treat FY21 (or HY21 annualised) as the final year. Subsequently, JEN's updated proposal and the AER's draft decision included final year increments escalated to June 2021 as opposed to December 2020 in the initial proposal.

14 AER, *Annual Benchmarking Report – Electricity distribution network service providers*, November 2020, p. 48.

15 AER, *Annual Benchmarking Report – Electricity distribution network service providers*, November 2020, p. 49.

- **comparing** three expenditure ratios for JEN–namely operating expenditure to total expenditure, operating expenditure to total cost and operating expenditure to total inputs–to those of its benchmark DNSPs.[16]

After observing that JEN's operating expenditure to total expenditure ratio was close to the benchmark comparator average, the AER concluded that JEN's capitalisation practices were not materially different to benchmark comparators – and, so, no adjustment was required. This is despite JEN's other two ratios (i.e. operating expenditure to total costs and operating expenditure to total inputs) being higher than the benchmark comparator average.

The above AER analysis does not address JEN's concern on the impact of capitalisation differences. Although we agree that both operating expenditure/capital expenditure trade-offs and capitalisation policies are important factors to be considered in benchmarking analysis, comparing simplified ratios will not accurately address our primary concern regarding the capitalisation policies of these DNSPs.

These ratios include more than just capitalisation policies and operating expenditure/capital expenditure trade-offs. They capture other differences such as differences in capital contribution policies, capital expenditure replacement cycles, augmentation and safety requirements, etc., which makes them unsuitable for use in the assessment of operating expenditure efficiency.

As such, these ratios cannot be relied upon as a credible tool in benchmarking without a proper understanding of the drivers behind the differences, especially in capital expenditure. Relying on them without appropriate adjustment captures capital expenditure differences that are unrelated to operating expenditure and provide a misleading assessment of the cost disadvantages faced by a DNSP due to capitalisation differences or other operating expenditure/capital expenditure decisions.

We provide analysis to show that although JEN's operating expenditure to total expenditure ratio is close to the benchmark comparators' average, JEN's efficiency score materially improves if the benchmark ratio is applied to all DNSPs to derive benchmarking results under a common capitalisation scenario. We provide more details on the information provided by ratios in section 2.1.1.2.

CEPA recommends that the AER separately analyse differences in capitalisation policy and operating expenditure/capital expenditure trade-offs and outlines an alternative approach to assess the impact of different capitalisation policies[17]. This approach compared JEN's efficiency scores when the 2019 CAM were used rather than the 2014 CAM. CEPA's analysis shows that differences in capitalisation policies have a material impact on JEN's benchmarking results. We provide more details on CEPA's analysis in section 2.1.1.3.

The capitalisation differences clearly need to be accounted for either through a positive OEF adjustment under 2014 CAM or by supplementing the AER's current assessment with benchmarking results based on the 2019 CAMs or a common CAM for all DNSPs. We discuss this in more detail in section 2.1.4.

2.1.1.1 Capitalisation is important

As explained in our initial proposal, capitalisation differences amongst DNSPs can have a material impact on benchmarking performance.

16 The AER calculated a benchmark by combining the ratios for four comparator DNSPs whose efficiency scores from operating expenditure econometric models are above 75%, namely Powercor, Citipower, United Energy, and SA Power Networks.

17 CEPA, *The Australian Energy Regulator's operating expenditure benchmarking – a review of the impact of capitalisation and model reliability*, 13 November 2020, p. 5.

The AER recognises that it needs to consider this particular issue further. In its 2020 benchmarking report,[18] the AER noted its intent to consult on capitalisation issues with stakeholders over the next 12 months, including on:

1. The most appropriate methods to measure differences in capitalisation practices across DNSPs and the capacity of these measures to account for material capitalisation policy differences and operating expenditure/capital expenditure trade-offs.
2. Where these measures indicate that a DNSP's capitalisation practices are materially different to the comparator DNSPs, the best way to address this, including to:
   a) apply an OEF adjustment to the efficiency results under the current benchmarking approach
   b) modify the approach to benchmark based on operating expenditure plus a fixed proportion of overheads
   c) modify the approach to benchmark based on DNSPs' current CAMs
   d) develop a common CAM for benchmarking purposes
   e) move to total expenditure benchmarking as a complement or substitute for the current approach.

Although we support this consultation, we also see capitalisation as an important issue to resolve ahead of making a final decision for JEN. In our view, it is inappropriate to leave this unresolved in that decision as it risks undermining our ability to recover our efficient operating costs and provide our customers with the service outcomes they seek over the next regulatory period.

2.1.1.2 Operating expenditure to total expenditure ratios provides little insight

In its draft decision, the AER undertook analysis using three ratios – operating expenditure to total cost, operating expenditure to total expenditure and operating expenditure to total inputs ratios. It considers that these ratios provided a good indication of the difference in capitalisation practices across DNSPs that covers both capitalisation policy and operating expenditure/capital expenditure trade-offs. JEN's operating expenditure to total cost ratio and operating expenditure to total inputs ratio are both higher than the benchmark comparator DNSP average. However, the AER concluded that JEN does not favour operating expenditure over capital expenditure more than the comparator DNSPs based solely on JEN's operating expenditure to total expenditure ratio being close to the comparator average.

We agree with the AER that the operating expenditure to total expenditure ratio accounts for more than just capitalisation policy and can include operating expenditure capital expenditure trade-offs. However, this ratio also captures other differences that make them unsuitable for assessing operating expenditure efficiency. For instance, capital expenditure can differ between DNSPs due to different asset replacement cycles, asset age profiles, and capital contribution levels.

CEPA also noted that:[19]

> *DNSPs could be spending more or less capex than other DNSPs without a noticeable change to their outputs. For example, a DNSP could have relatively high capex (over the period used for benchmarking) to increase capacity or to replace a higher proportion of assets.*
>
> *The issue is not that ratios do not capture the capitalisation and opex/ capex trade-off or provide some information. The issues associated with only reviewing the ratios are that:*
>
> - *The impact of capitalisation and opex/ capex trade-off cannot be assessed separately. The former is an accounting policy that should not affect the DNSPs' measured opex efficiency, while the latter is an operational choice that can affect the DNSPs' measured opex efficiency but needs to be considered against the DNSPs' capex efficiency.*

18 AER, *Annual Benchmarking Report – Electricity distribution network service providers*, November 2020, pp. 7, 48–49, 75–88.

19 CEPA, *The Australian Energy Regulator's operating expenditure benchmarking – a review of the impact of capitalisation and model reliability*, 13 November 2020, p. 15.

- *The ratios do not provide information on the DNSP's position in their asset replacement cycle, the DNSP's efficiency/ inefficiency of capex, the DNSP's overall totex relative to outputs, or the DNSP's pre-capitalisation opex levels.*

These drivers of capital expenditure differences may not impact a DNSP's operating expenditure efficiency but may nevertheless influence the operating expenditure to total expenditure ratio. In Table 2–2, we provide a simplified example that we provided in our submission to the AER's draft 2020 benchmarking report to illustrate that even a simple difference in capital contribution level could distort the operating expenditure to total expenditure ratio.[20] This example shows how factors impacting capital expenditures between DNSPs are irrelevant to assessing operating expenditure efficiency assessment.

Similarly, CEPA also provided three stylised examples in its report to illustrate how the operating expenditure to total expenditure ratio can be misleading when assessing operating expenditure efficiencies.[21] Based on these examples, CEPA concluded that:[22]

> *even relatively small differences in capitalisation policies (e.g. 5%) can have large impacts on the measured efficiency scores, while the difference in opex/totex ratios may appear small. The ratios are affected by a range of factors beyond the DNSPs' capitalisation policies. Therefore, even if the AER continues to use opex/ totex (and other) ratios, the AER would need to consider the difference in ratios in much greater detail rather than relying on the 'in the range' analysis that it has used in its draft decision.*

The AER, in its 2020 draft benchmarking report, examined the capitalisation issue and expressed its preference to rely on the operating expenditure to total expenditure ratio to provide a high-level view of the net effect of both capitalisation policy and operating expenditure/capital trade-offs. On this basis, it considered that the operating expenditure to total expenditure ratio as a high-level measure was superior to partial measures that only focus on, for example, capitalisation of overheads. The AER then concludes that the operating expenditure to total expenditure ratios are similar across DNSPs–and, therefore, that the capitalisation practices are unlikely to have a sizeable impact on efficiency results for most DNSPs.[23]

In our view, although operating expenditure to total expenditure ratios can provide a high-level view of the overall expenditure profile, it cannot be assumed that this ratio only covers operating expenditure/capital expenditure trade-offs and the capitalisation policies. DNSPs having similar operating expenditure to total expenditure ratios does not imply that their capitalisation practices are similar nor that those practices do not materially impact operating expenditure efficiency results.

Table 2–2 shows that even when the operating expenditure to total expenditure ratio is the same across DNSPs, it may not accurately reflect the capitalisation differences impacting operating expenditure efficiencies due to factors unrelated to operating expenditure assessment (e.g. capital contribution) distorting the ratios.

Table 2–2: Simplified example on operating expenditure to totex ratio impacting efficiency results

		DNSP1	DNSP2	DNSP3
Direct gross capital expenditure	[1]	100	100	100
Capital contribution	[2]	30	10	10
Direct net capital expenditure	[3]=[1]-[2]	70	90	90
Operating expenditure excl. overheads	[4]	100	100	100
Pre-capitalised overheads	[5]	50	50	50
Capitalisation ratio (of overheads)	[6]	50%	50%	25%

20 JEN, *Feedback on the draft 2020 Annual Benchmarking Report – 10 November 2020*, Pg. 2-3.

21 CEPA, *The Australian Energy Regulator's operating expenditure benchmarking – a review of the impact of capitalisation and model reliability*, 13 November 2020, pp. 14–15.

22 CEPA, *The Australian Energy Regulator's operating expenditure benchmarking – a review of the impact of capitalisation and model reliability*, 13 November 2020, p. 15.

23 AER, *2020 Annual Benchmarking Report - Electricity distribution network service providers*, November 2020, p. 49.

		DNSP1	DNSP2	DNSP3
Operating expenditure incl. expensed overheads	[7]=[4]+[5]*(1-[6])	125	125	137.5
Gross capital expenditure incl. capitalised overheads	[8]=[1]+[5]*[6]	125	125	112.5
Net capital expenditure incl. capitalised overheads	[9]=[3]+[5]*[6]	95	115	102.5
Total expenditure based on gross capital expenditure	[10]=[7]+[8]	250	250	250
Total expenditure based on net capital expenditure	[11]=[7]+[9]	220	240	240
Total expenditure 'efficiency' based on gross capital expenditure	[12]=1/([10]/min([10]))	1.00	1.00	1.00
Operating expenditure to total expenditure (based on net capital expenditure) ratio	[13]=[7]/[11]	57%	52%	57%
Operating expenditure 'efficiency'	[15]=1/([7]/min([7])	1.00	1.00	0.91

In the example in Table 2–2 above:

- the three DNSPs have the same outputs, being total expenditure based on gross capital expenditure level, operating expenditure and capital expenditure preference, and overheads level
- the only difference between DNSP1 and DNSP2 is in the capital contribution (item [2] above). This difference should not impact the operating expenditure efficiency assessment–however, when looking at the operating expenditure to total expenditure ratio, DNSP2 appears to be less efficient at 52% compared to DNSP1 of 57% due to lower overall expensing proportion
- the only difference between DNSP2 and DNSP3 is in overheads capitalisation ratio (item [6] above, as a representation of capitalisation policy). This should not impact the operating expenditure efficiency assessment–however, when looking at the operating expenditure to total expenditure ratio, DNSP1 and DNSP3 have the same ratio (item [13] above); the cost disadvantage of lower capitalisation ratio faced by DNSP3 is masked by its lower capital contribution
- although DNSP1 and DNSP3 have different capitalisation policies and the same operating expenditure/capital expenditure trade-offs, this is not reflected in the operating expenditure to total expenditure ratio – which materially impacts the comparability of operating expenditure efficiency results.

The Table 2–2 example highlights how just one factor – different levels of capital contributions – can affect reported operating expenditure to total expenditure ratios. Other factors, such as the position in the asset replacement cycle, and augmentation and safety requirements can have similar effects. As such, without adjustment for these factors, the ratio cannot provide meaningful insight into the specific question of whether the DNSPs' capitalisation practices impact operating expenditure benchmarking results.

For this reason, CEPA recommends that the AER separately analyse capitalisation policy and operating expenditure/capital expenditure trade-off differences.[24] Capitalisation policies are accounting policies that do not change the way the required outputs are delivered, whether by a capital or operating solution. That accounting treatment is largely independent of operating expenditure/ capital expenditure trade-offs and other differences in capital expenditure drivers that require a separate assessment of capital expenditure.

[24] CEPA, *The Australian Energy Regulator's operating expenditure benchmarking – a review of the impact of capitalisation and model reliability*, 13 November 2020, p. 5.

The AER noted in its draft decision that the operating expenditure/capital input trade-offs are captured in the econometric models because the capital input[25] and outputs (e.g. customer numbers and ratcheted maximum demand) in the Australian data are highly correlated when Economic Insights tested the inclusion of capital inputs into econometric models in a previous study[26]. Economic Insights then concludes that omitting capital inputs in econometric modelling is unlikely to significantly affect the efficiency results as the capital inputs are likely to be captured in the outputs.[27]

Given that the AER considers that the relationship between capital inputs and operating expenditure is likely captured in the operating expenditure models already, the AER should now seek to isolate and adjust for capitalisation policy differences separately to the assessment of operating expenditure/ capital expenditure trade-offs. Even if the AER continues to rely on high level operating expenditure to total expenditure ratios to measure the difference in capitalisation practices, it should not rely on them to conclude that JEN's capitalisation practices are not materially different from the benchmark comparators without investigating the capital expenditure differences amongst DNSPs in more detail.

As the comparison in Table 2–3 shows, JEN's ratios are all higher than the benchmarking comparator weighted average over both the 2006–2019 and 2012–2019 periods. As there are limitations to all three ratios, we consider it more appropriate to at least take the average of all three ratios in determining a capitalisation OEF for JEN (as shown in the bottom row of the table).

Table 2–3: JEN and benchmark comparators' ratios based on 2014 CAM

Ratios	JEN		Benchmark comparator weighted average(1)		Difference (JEN *minus* comparator)	
	2006–19	2012–19	2006–19	2012–19	2006–19	2012–19
Operating expenditure to total expenditure	42.7%	41.0%	42.5%	40.6%	+0.2%	+0.4%
Operating expenditure to total cost	42.5%	41.5%	36.2%	37.0%	+6.3%	+4.6%
Operating expenditure to total inputs	118.1%	120.2%	96.3%	98.8%	+21.8%	+21.4%
Average of 3 ratios					**+9.4%**	**+8.8%**

(1) This is calculated as the weighted average of the benchmark comparators Citipower, Powercor, SA Power Networks and United Energy weighted by customer numbers consistent with the AER's approach in the draft decision. This calculation is included in Attachment 05-07.

Use of a common capitalisation approach

If the AER intends to continue relying on the operating expenditure to total expenditure ratio in assessing the difference in capitalisation practices, an alternative approach is to apply a common capitalisation to all DNSPs' operating expenditure and derive the benchmarking results base on this normalised operating expenditure. The advantage of this approach is that it removes the need for a capitalisation OEF adjustment as the capitalisation for all DNSPs are on a comparable basis. In this section we provide our analysis under this alternative approach.

To assess JEN's operating expenditure efficiency under this approach, we:

1. apply the AER's preferred operating expenditure to total expenditure ratio of the benchmark comparator DNSPs weighted average of the full sample period 2006-19 (i.e. 42.5% from Table 2–3

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25 Economic Insights defines capital input as the aggregate of physical measures of lines, cables, and transformers with annual user costs being used as the weights.

26 Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November 2014, p. 32.

27 AER, *Draft decision – Jemena 2021–26, Attachment 6: Operating expenditure, September 2020*, p. 89; and Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November 2014, p. 32.

above) to all thirteen Australian DNSPs' network services total expenditure to derive their normalised operating expenditure in each year

2. use the new data series with the normalised operating expenditure in undertaking the econometric benchmarking analysis

3. derive operating expenditure efficiency scores and the efficient rolled-forward operating expenditure using AER's standard approach[28]

This analysis shows that JEN's efficiency score materially improves by 6-7%. As JEN's operating expenditure to total expenditure ratio (42.7%) is close to the benchmark comparator average of 42.5%, the efficient operating expenditure derived from the econometric models under this common capitalisation scenario is comparable to JEN's actual base year operating expenditure. JEN's network services operating expenditure proposal of $78M (i.e. $82M actual base year operating expenditure less $4M per annum reduction) is in the range of the benchmark efficient operating expenditure of $74M to $78M, as shown in Table 2–4.

Table 2–4: JEN's operating expenditure efficiency under the common capitalisation approach

	Economic Insights (2014 CAMs)	Common Capitalisation Approach
Efficiency scores		
Average Cobb-Douglas models[29] – 2006-2019	0.63	0.68 (+7%)
Average Cobb-Douglas models – 2012-2019	0.60	0.64 (+6%)
Efficient rolled forward operating expenditure ($2021, millions)		
Average Cobb-Douglas models – 2006-2019	72	78 (+8%)
Average Cobb-Douglas models – 2012-2019	68	74 (+9%)
Range of benchmark efficient operating expenditure for JEN		**74 to 78**
JEN actual base year network services operating expenditure ($2021, millions)		
Base year operating expenditure		82
Base year operating expenditure with $4M reduction		**78**

Source: JEN Analysis on Economic Insights 2019 Benchmarking dataset (See Attachment 05-07 for more details)

The above analysis illustrates that, even if the operating expenditure to total expenditure ratio is used to assess capitalisation differences, JEN's operating expenditure to total expenditure ratio—being close to the benchmark comparator DNSPs average—does not mean JEN's efficiency is not adversely impacted by the capitalisation differences amongst DNSPs. On the contrary, when the operating expenditure to total expenditure ratio is used to derive a common capitalisation practice across DNSPs, JEN's efficiency materially improves and is in the range of efficient operating expenditure derived by the econometric models.

2.1.1.3 Applying the 2019 CAM does provide useful insight

Economic Insights' economic benchmarking is based on data that reflects the CAMs (and capitalisation policies) applied by DNSPs in 2014. The primary reason for fixing CAMs was to remove incentives for DNSPs to improve their measured operating expenditure efficiency by amending CAMs.

In our view, given that measurement practice, it is safe to assume that DNSPs have not sought to amend their CAMs in a way to improve benchmarking position. If true, then it is also reasonable to assume that changes made by DNSPs to their capitalisation policies (and CAMs) since 2014 reflect genuine changes to accounting

[28] The AER's standard approach to roll forward efficient operating expenditure from econometric models is described in the AER's operating expenditure draft decision for JEN (on page 37 of '*AER – Draft decision – Jemena 2021–26, Attachment 6: Operating expenditure – September 2020*'). We provide our calculations and model outputs for this analysis in Attachment 05-07.

[29] We discuss why we have not included translog models in section 2.1.2.

policies and practices due to changes in corporate and cost structures rather than changes intended to improve measured operating expenditure efficiency.

This is important for two reasons:

- **First**, capitalisation policies are not the same across DNSPs and also change over time, which can materially impact the comparability of benchmarking results
- **Second**, economic benchmarking undertaken using data that reflects *current* CAMs, rather than those that applied in 2014, can provide useful insights without concern of bias or gaming.

In its report, CEPA sought to test the impact that differences in capitalisation policies can have on benchmark results. To do so, CEPA compared JEN's efficiency scores reflected in data based on the 2019 CAMs to that reflected in the 2014 CAMs. As shown in Table 2–5, the impact is material with a significant improvement in efficiency score over both the 2006–2019 and 2012–2019 time periods.

Table 2–5: JEN's operating expenditure efficiency score under different CAMs

	Economic Insights (2014 CAMs)	2019 CAMs
2006–2019		
Average all models	0.62	0.71 (+15%)
Average Cobb-Douglas models	0.63	0.74 (+17%)
2012–2019		
Average all models	0.55	0.64 (+15%)
Average Cobb-Douglas models	0.60	0.69 (+15%)

This analysis highlights just how much of an impact the differences in capitalisation policies can have on efficiency scores. As a minimum, it suggests that the AER should reconsider its draft decision that capitalisation differences do not materially affect JEN's operating expenditure benchmarking efficiency score.

When we assess benchmarking results under the 2014 CAMs and 2019 CAMs independently and rely on the operating expenditure to total expenditure ratio to inform the capitalisation differences under each CAM scenario, our analysis shows that it leads to the same conclusion that JEN's efficiency materially improves under the current 2019 CAMs.

Under the 2019 CAMs, JEN's operating expenditure to total expenditure ratio is 3.4% below the benchmark comparator DNSP average, as shown in Table 2–6. Based on our discussions with the AER after the draft decision, we understand that the AER's preliminary analysis indicates that JEN has gained a cost advantage compared to the benchmark comparators under the 2019 CAM. JEN would therefore need to be adjusted by a negative OEF adjustment of 3.4% based on the operating expenditure to total expenditure ratio. If this negative OEF is included, JEN's efficiency improves by 11% under the 2019 CAMs compared to 2014 CAMs. We show this analysis in more detail in section 2.1.4 and in attachment 05-07.

Table 2–6: JEN and benchmark comparators' ratios based on 2019 CAMs

Ratios[30]	JEN		Benchmark comparator weighted average		Difference (JEN *minus* comparator)	
	2006–19	2012–19	2006–19	2012–19	2006–19	2012–19
Operating expenditure to total expenditure	42.7%	41.0%	46.1%	44.3%	**-3.4%**	**-3.4%**

30 We were unable to calculate the other two ratios under 2019 CAMs as the published RIN data was insufficient for us to derive the total cost which requires reallocating overheads into/out of various RAB asset classes for the three impacted DNSPs.

2.1.1.4 The AER should include an OEF for capitalisation policies

Based on the above, we conclude that:

- differences in capitalisation policies can–and in JEN's case do–have a material impact on operating expenditure efficiency results that cannot be ignored
- capitalisation policies and operating expenditure/capital expenditure trade-offs are two very distinct factors that affect reported operating expenditure and need to be assessed separately
- operating expenditure/capital expenditure trade-offs, according to the AER, are already partially reflected in the operating expenditure econometric models applied by Economic Insights and relied on by the AER–and so the focus should be on differences in capitalisation policies
- if the operating expenditure ratios are used to assess the impact of capitalisation differences, then more detailed investigation into capital expenditure is required and the ratios need to be adjusted accordingly to avoid inadvertently including irrelevant capital expenditure differences
- JEN's efficiency score materially improves under an alternative common capitalisation approach (using operating expenditure to total expenditure ratios) and JEN's operating expenditure proposal with $4M per annum reduction is within the benchmark efficient range
- to adjust those operating expenditure ratios properly, to reflect the differences in capitalisation policies only, requires more data. This activity does not appear feasible in time for the AER's final decision for JEN.

Given this, we propose that the AER should assess the efficiency of JEN's base operating expenditure using *both* its 2014 and 2019 CAMs, with the latter being the most relevant given that it better reflects the current cost structure of DNSPs and that most likely to apply over the next regulatory period:

- if relying on the operating expenditure efficiency scores based on the 2014 CAMs, then adopt an OEF for capitalisation, based on one of two options:
  - **Option 1:** adopt a value of **15%** for both the 2006–19 and 2012–19 periods based on CEPA's comparison of JEN's efficiency scores from applying the 2014 and 2019 CAMs, or
  - **Option 2:** adopt, more conservatively, **9.4%** for the 2006–19 period and **8.8%** for the 2012–19 period based on an average of the three operating expenditure ratios for the respective periods
- if benchmarking results are **based on 2019 CAMs** being used, then consider a third option:
  - **Option 3:** adopt an OEF for capitalisation of **-3.4%** for both the 2006–19 and 2012-19 periods.

Table 2–7 summarises the OEF adjustments under each CAM scenarios, by analysis period. Although we have included Option 2 under the 2014 CAM scenario, our preference – and CEPA's recommendation – is to adopt Option 1 under that scenario. Relying on the operating expenditure ratios under Option 2 will be excessively conservative because these ratios are not adjusted for other factors that may affect the level of capital expenditure and operating expenditure beyond just capitalisation practices.

Table 2–7: Summary of JEN's capitalisation OEF adjustment

	Capitalisation OEF adjustment	
	2006–2019	2012–2019
2014 CAM – Option 1 – CEPA recommendation	+15%	+15%

	Capitalisation OEF adjustment	
	2006–2019	2012–2019
2014 CAM – Option 2 – Average of three ratios	+9.4%	+8.8%
2019 CAM – Option 3 – Adjustment based on ratios	-3.4%	-3.4%

2.1.2 Translog models should not be used for JEN

In its draft decision for JEN, the AER estimated efficient operating expenditure by:

- relying on operating expenditure efficiency scores from four econometric models (SFA CD, LSE CD, SFA TL, LSE TL) over two sample periods (2006–19 and 2012–19) to estimate efficient operating expenditure in the 2018 base year, including by applying assumed OEFs
- calculating the average efficient operating expenditure from the models that it considers satisfies the monotonicity requirements
- comparing the average benchmark efficient operating expenditure to JEN's actual 2018 operating expenditure, and
- concluding that JEN's 2018 operating expenditure was materiality inefficient and a 15% reduction was needed when using it to determine base operating expenditure.

As such, a key input to the AER's draft decision conclusion were the benchmarking results from the translog models (i.e. LSE TL and SFA TL), which are prone to monotonicity violations.

In the AER's latest 2020 draft benchmarking report, monotonicity violations were more evident than in the previous year's report. Although these violations existed in prior years, it is now more pronounced and significantly impacting the models available to JEN. This means that:

- only two models (SFA CD and LSE CD) over 2012–19 and three models (SFA CD, LSE CD, and LSE TL) over 2006–19 period remain available for the AER, and
- although the LSE TL model does not, strictly speaking, suffer from monotonicity violations over the 2006–19 period, its results are an outlier in that it produces unjustifiable elasticities (i.e. output weights) and gives significantly lower results than all other econometric models in previous years.[31]

The latter point was acknowledged by Economic Insights:[32]

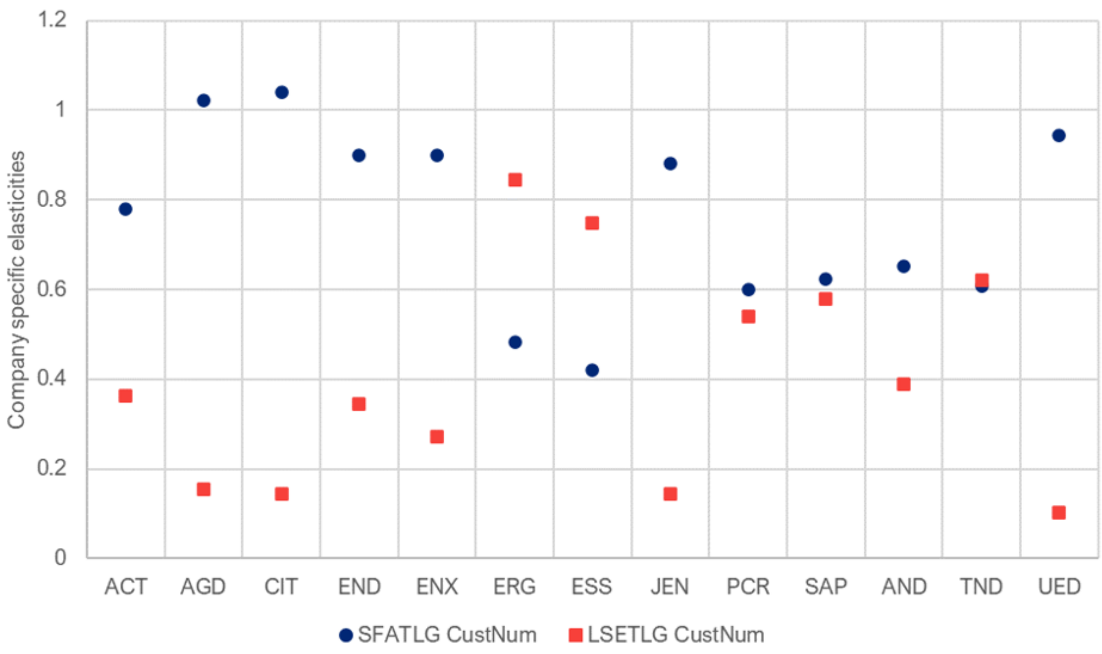
> *the LSETLG model produces noticeably lower efficiency scores for CIT, JEN and UED compared to the other cost function models.*

CEPA also expressed its concerns with the significant differences in elasticities between the SFA TL and LSE TL models for the 2006–19 period given that they have identical specifications. For instance, as reproduced in Figure 2–1, CEPA shows that there are excessive differences in the weights estimated for customer numbers between the two translog models for most DNSPs.

31 Furthermore, as the number of available models for JEN reduced to 5 (including LSE TL) this year compared to a total of 8 models, the weight of each model significantly increases when the AER takes the average across all available models. This means that the outlier LSE TL model carries more weight in the average and can adversely bias the results more than what it would have been if all 8 models were available.

32 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 DNSP Annual Benchmarking* Report, 25 August 2020, p. 30.

Figure 2–1: Customer number elasticities derived under SFA TL and LSE TL



Source: Economic Insights, CEPA analysis

Importantly, the differences in customer number weights between the two translog models are the most significant for CitiPower, JEN and United Energy. These three DNSPs are those, as noted by Economic Insights, suffering from '*noticeably lower efficiency scores*' and prone to monotonicity violations either with the SFA TL or LSE TL models.

For CitiPower, JEN and United Energy the LSE TL model output weights for customer numbers are only 10% to 14%. This contradicts the findings from all other operating expenditure econometric models adopted by the Economic Insights that customer numbers is the most significant driver of operating expenditure and has output weights of 50% to 60%.

CEPA raises concerns in its report that: [33]

> *Elasticities show the percentage change in opex required to deliver a percentage change in the outputs. For example, Jemena's average customer number elasticity varies from 0.14 in one model (LSE TL) to 1.04 in another (SFA TL). This indicates that, in the first model, Jemena's opex increases by 0.14% for every 1% increase in customer numbers, while in the second model Jemena's opex increases by 1.04% for every 1% increase in customer numbers.* ***These differences are inconsistent with economic and engineering theory****. [emphasis added]*

Although there are no monotonicity violations this time on LSE TL for JEN, the large unexplained discrepancy in weights between the two translog models and the non-credible low output weights to customer numbers raise significant concerns on the reasonableness and reliability of these model results to determine operating expenditure allowances.

Given these concerns, we urge the AER to reconsider using the LSE TL model to assess JEN's operating expenditure efficiency purely based on monotonicity conditions. Without understanding and being comfortable with the material discrepancies in the model results, it would be inappropriate to rely on them in the final decision for JEN. Doing otherwise could significantly underestimate JEN's actual efficiency level and lead the AER to form incorrect conclusions about JEN's base efficient operating expenditure.

[33] CEPA, *The Australian Energy Regulator's operating expenditure benchmarking – a review of the impact of capitalisation and model reliability*, 13 November 2020, Pg. 4

CEPA also considered that it is best to use Cobb-Douglas models for assessing JEN's base year efficiency and notes the following:[34]

> *Given these issues, we are of the view that the AER should not put any weight on the results of the translog models in making its decision on Jemena's opex allowance.*

For the above reasons, we urge the AER to exclude the LSE TL model over 2006–19 when assessing JEN's operating expenditure efficiency.

2.1.3 Vegetation management OEF is overstated

In its draft decision, the AER included a negative OEF adjustment to JEN's base operating expenditure for vegetation management regulatory obligations costs. In our view, this adjustment is likely overstated because it relies on historical allowance rather than actual vegetation management costs for Victorian DNSPs.

The AER identified differences in vegetation management regulatory obligations as a potential OEF. To estimate the OEF for these costs, the AER used historical allowances for vegetation management costs over 2011–15 for Victorian DNSPs that were estimated in 2010. For JEN, this equated to a negative OEF of negative 1.49% for the 2006–18 period and negative 2.42% for the 2012–18 period. This was the only material OEF applied to JEN in the draft decision.

Although a useful starting point, relying on forecast data from ten years ago to estimate the OEF is unlikely to reflect the actual cost disadvantages faced by DNSPs, particularly given what the actual vegetation management cost data shows. We consider the OEF can be refined by comparing 2009 and 2010 *actual* vegetation management operating expenditure for Victorian DNSPs to the 2011–18 actual costs from their CA RIN responses.

Our concern with relying on vegetation management *allowances* or forecast costs, rather than actual costs is that this could overstate the estimated OEF because actual vegetation management costs could be lower than those allowed by the AER for the relevant Victorian DNSPs. Our logic is as follows:

- the vegetation management OEF should reflect the impact on actual costs due to changes in vegetation management obligations – this is because the OEF is used to adjust benchmarking results that are based on actual operating expenditure
- actual vegetation management costs provide a more accurate indication of that impact than forecast costs
- actual costs *are* available in the RIN responses provided by the Victorian DNSPs and these increased vegetation management costs were, in fact, close to or lower than the allowances – which suggests that relying on allowed or forecast costs would likely result in inaccurate estimates of the true cost
- if – as we propose – actual costs were used to estimate the OEF – as opposed to the allowances – then it gives a noticeably smaller negative OEF for JEN of negative 1.21% over the 2006–19 period or negative 1.88% over the 2012–19 period, instead of negative 1.49% and negative 2.42% respectively.

The reason for the noticeable impact on this OEF is due to the difference in CitiPower's actual costs compared to its allowances.[35] We recommend the AER at least request additional actual data from CitiPower to make a complete assessment on vegetation management costs to ensure it does not unreasonably penalise JEN. Alternately it may consider adopting the approach of taking an average of OEFs based on allowance and available actual data.

[34] CEPA, *The Australian Energy Regulator's operating expenditure benchmarking – a review of the impact of capitalisation and model reliability*, 13 November 2020, p. 8.

[35] CitiPower's actual incremental vegetation management cost pre and post 2011 is 2% of its total operating expenditure whereas the historical allowance indicates 7%. This analysis is provided in Attachment 05-07.

Table 2–8: Vegetation management OEF adjustment

	Vegetation management OEF	
	2006–2019	2012–2019
AER's approach based on allowance data	-1.5%	-2.4%
JEN's approach based on actual data	-1.2%	-1.9%
Average of the two approaches	-1.3%	-2.2%

2.1.4 Our base year is not materially inefficient

As shown above, JEN's base year operating expenditure is in line with the benchmark after accounting for:

- differences in capitalisation policies by including capitalisation OEFs or adopting the current CAM
- updates made to the vegetation management OEF
- removal of the LSE TL model that are prone to reliability issues.

Table 2–9 summarises the OEFs for JEN under 2014 CAM scenario if we combine the updated vegetation management OEFs with those proposed above for capitalisation policies (under either Option 1 or Option 2). The AER's historical practice is to include other OEFs identified by Sapere Merz. However, in JEN's case, these were estimated to be zero.

Table 2–9: Summary of OEF applicable to JEN under 2014 CAM scenario

OEF adjustment		2006–2019	2012–2019
Vegetation management obligations – based on actuals	[1]	-1.2%	-1.9%
Capitalisation – Option 1 – CEPA recommendation	[2]	+15%	+15%
Capitalisation – Option 2 – Average of ratios	[3]	+9.4%	+8.8%
Total OEF – 2014 CAM – Option 1 – CEPA recommendation	**[1]+[2]**	**+13.8%**	**+13.1%**
Total OEF – 2014 CAM – Option 2 – Average of ratios	**[1]+[3]**	**+8.2%**	**+6.9%**

Table 2–10 summarises the OEFs for JEN under 2019 CAM if the AER were to rely on the operating expenditure to total expenditure ratio to adjust (under Option 3) for the difference in capitalisation between JEN and the benchmark comparators.

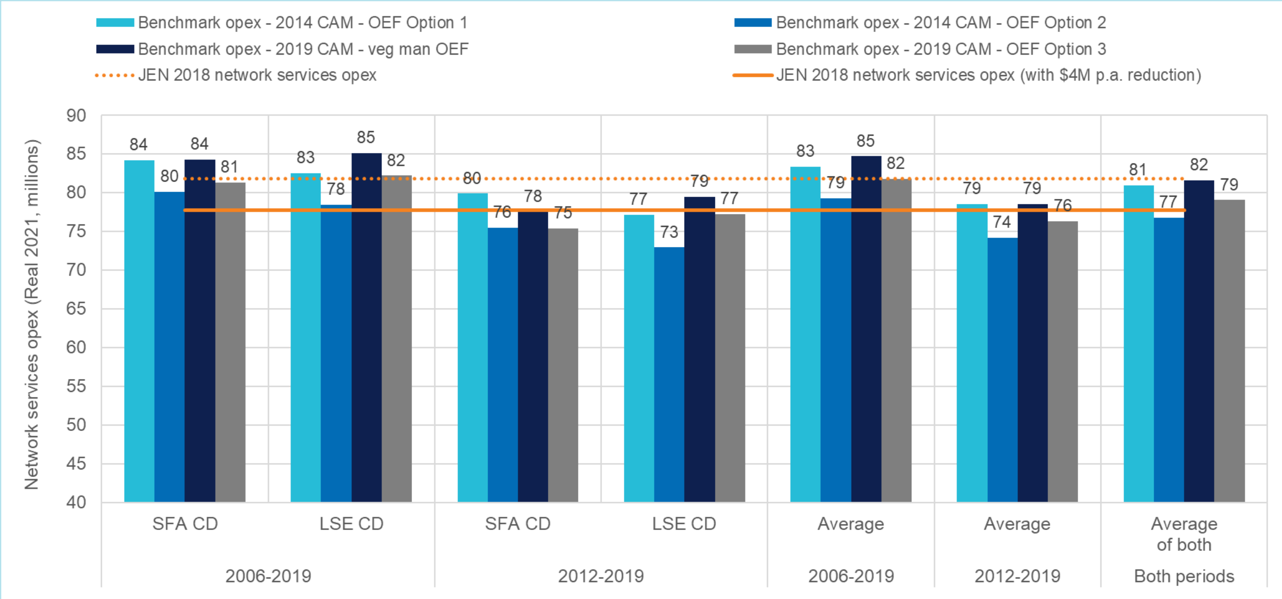
Table 2–10: Summary of OEF applicable to JEN under 2019 CAM scenario

OEF adjustment		2006–2019	2012–2019
Vegetation management obligations – based on actuals	[1]	-1.2%	-1.9%
Capitalisation – Option 3 – Adjustment based on ratios	[2]	-3.4%	-3.4%
Total OEF – 2019 CAM – Option 3	**[1]+[2]**	**-4.6%**	**-5.2%**

Adjusting for the OEFs and excluding the LSE TL model discussed above significantly improves the comparability of JEN's actual 2018 operating expenditure to the efficiency benchmarks. As shown in Figure 2–2 and in Attachment 05-07, once our proposed transformation savings of $4 million ($2021) per year are considered, JEN's operating expenditure is consistent with those benchmarks.[36]

[36] The benchmark operating expenditure is calculated using the AER's standard approach to roll forward the efficient operating expenditure derived by each applicable econometric model as described in the AER's operating expenditure draft decision for JEN (on page 37 of '*AER – Draft decision – Jemena 2021–26, Attachment 6: Operating expenditure – September 2020*'). Our calculations based on this approach are provided in Attachment 05-07.

Figure 2–2: JEN's base year operating expenditure compared to AER benchmark



Based on the above analysis we therefore do not accept the base year reduction of 15% applied by the AER in its draft decision. Instead, we propose to apply a $4 million annual reduction over the next regulatory period that we expect to deliver from our transformation program in 2019. This reduction materially benefits our customers as the benefits of that program are shared upfront with the customers without any EBSS benefit to JEN.

Our view differs from that in the draft decision primarily because we have adjusted for the impact of capitalisation differences. As discussed above:

- CEPA's analysis shows that our efficiency score materially improves (by 15% to 17%) once proper adjustments are made for DNSPs' capitalisation policies
- although we do not agree that the three operating expenditure ratios considered by the AER in the draft decision provide insight into how differences in capitalisation practices affect reported operating expenditure efficiency, our own analysis of those ratios indicates that an average OEF of 9% may apply to JEN if they were used to adjust for such differences.

Once this factor – and our concerns with the translog models and the vegetation management OEF – are properly considered, the evidence supports our proposal to use JEN's actual 2018 as the base operating expenditure without an efficiency adjustment. Using that base operating expenditure as a starting point, our proposed revised proposal operating expenditure satisfies the efficiency and prudency requirement of the NER and will support and maintain our current service quality levels.

Our key concern is that using a deterministic benchmarking approach to set base operating expenditure–such as applying a 15% reduction based on high-level benchmarking models–is likely to create financeability issues for JEN in a low-interest rate environment that could result in deterioration of service quality levels which is not in the long term interests of our customers.

2.1.5 MTFP results should not be relied upon

The AER has also considered MTFP results when assessing operating expenditure efficiency. However, for the reasons noted below, this is inappropriate at the present time due to reliability concerns and therefore, we did not factor MTFP results into our analysis of the base year in section 2.1.4.

Economic Insights and the AER noted in the 2020 benchmarking report that an error was identified in the way the MTFP output weights were calculated in all previous AER benchmarking reports. This has a significant impact on the MTFP and MPFP results for all DNSPs and causes a substantial reshuffle of DNSPs' rankings in favour of rural DNSPs.

Our expert economists, CEPA, reviewed Economic Insights' estimation approach of output weights and found that the output weights derived using the Leontief cost function are not robust to place any reliance on the efficiency results.

Economic Insights commented in its 2020 benchmarking report on the statistical performance of Leontief cost function that the:[37]

> *Leontief cost function will never produce impressive–looking statistical results…The statistical performance of a simple fixed proportions model cannot be judged by the same standards we would use for fitting smooth functions such as the Cobb–Douglas or translog.*

However, CEPA considers that while Economic Insights prefers to use Leontief cost function regressions due to their simplicity, it does not mean that results which are not robust should be relied upon and that the criteria for statistical performance should be lowered. Testing for statistical robustness helps to identify errors in the model and to understand whether confidence can be placed on the modelled relationships between inputs and outputs.

CEPA highlighted in its report that[38]:

> *We do not consider that requiring a regression model to be a able to reasonably explain the variations in the independent variable is "judg[ing]… [the Leontief cost functions] by the same standards we would use for fitting smooth functions such as the Cobb-Douglas or translog". We consider that modelling results should be robust, replicable and transparent.* ***If a regression-based model cannot be judged on its statistical performance then, in our view, the model probably should not be used****. (emphasis in original quote)*

The two most concerning statistical issues with the Leontief cost functions are that most coefficients (used in calculating MTFP output weights) produced:

1. are statistically insignificant
2. do not adequately explain the variation of operating expenditure from its mean (represented by very low R^2 values).

For instance, 28 out of 52 models (54%) produce:

- only a single significant output coefficient
- 17 (33%) produce 2 significant coefficients, and
- 2 (4%) produce 3 significant coefficients.[39]

Most coefficients are not statistically different from zero, and when they are, they vary significantly across DNSPs. However, Economic Insights has previously noted it is willing to accept statistically insignificant coefficients.[40]

37 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 DNSP Annual Benchmarking Report*, 13 October 2020, Pg. 11

38 CEPA, *The Australian Energy Regulator's operating expenditure benchmarking – a review of the impact of capitalisation and model reliability*, 13 November 2020, p. 27.

39 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 DNSP Annual Benchmarking Report – Draft*, August 2020, p. 123.

40 Economic Insights, *Memorandum: Forecast Operating expenditure Productivity Growth, to 'AER Operating expenditure Team'*, 4 February 2019.

In addition, CEPA highlighted that the R^2 values for 8 DNSPs (out of 13 in total) are below 0.5 – indicating poor goodness-of-fit.[41] The R^2 value represents the proportion of the variance that is explained by the model. For example, a value of 1.0 would mean that the model explains all the variation of operating expenditure from its mean. Therefore, an R^2 value below 0.5 indicates that the model could only explain less than half of the variation in operating expenditure – this is clearly problematic.

Given the importance of these coefficients in setting the output weights and that the majority of the R^2 values are very low, no conclusion on the weights can be meaningfully drawn. Testing the MTFP results–which we consider non-robust–against the assessment principles in the expenditure forecast assessment guidelines suggests that it is not appropriate for the AER to rely on them when setting JEN's operating expenditure allowance.[42]

In this case, CEPA notes that: [43]

> *In addition, we do not consider that the multilateral productivity approaches currently meet the AER's assessment principles that are set out in its expenditure forecast assessment guidelines, given:*
>
> - *the limited statistical significance of the weights does not meet the '**robustness**' principle, and*
> - *the materially different coefficients in the Leontief cost function regressions do not meet the '**accuracy and reliability**' or '**robustness**' principles.*
>
> *(emphasis in original quote)*

Given the Economic Insights has advised the AER to use the new weights based on non-robust results, the AER should seek a second opinion from an independent expert to validate benchmarking modelling to ensure that its decision-making is well informed and are not prone to anchoring/unconscious bias. Without this, we do not consider that any reliance can be confidently placed on the MTFP and MPFP results.

2.2 Application of any efficiency adjustment

For the reasons explained in section 2.1, we do not consider that an efficiency adjustment needs to be applied to our 2018 base year operating expenditure. However, if one is applied, then certain matters must be accounted for:

- **First**, any efficiency adjustment should be applied only to reported operating expenditure, not to the newly expensed corporate overheads.
- **Second**, as the draft decision proposed, a transition (e.g. via a glide path step change) should be used before arriving at the top-down efficiency adjustment to better reflect what is realistically achievable to preserve service outcomes for customers.

We discuss each matter below.

2.2.1 Not apply to newly expensed corporate overheads

Any efficiency adjustment should only be applied to base operating expenditure and not to newly expensed corporate overheads that were not part of the base year operating expenditure. This is because those overheads were not subject to the economic benchmarking and so it would be inappropriate to adjust them as if it did.

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41 CEPA, *The Australian Energy Regulator's operating expenditure benchmarking – a review of the impact of capitalisation and model reliability*, 13 November 2020, p. 26.

42 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 17–18.

43 CEPA, *The Australian Energy Regulator's operating expenditure benchmarking – a review of the impact of capitalisation and model reliability*, 13 November 2020, p. 26.

These overheads represent a movement in expenditure from capital expenditure to operating expenditure and reflect changes to JEN's accounting policy to expense the currently capitalised corporate overheads from 1 January 2021 onwards. The change resulted in $12 million per year of newly expensed corporate overheads in the operating expenditure forecast for the next regulatory period–treatment that is consistent with the AER's recent final decision for Jemena Gas Networks.

In JEN's draft decision, the AER has approved $12 million per year to be included in our operating expenditure forecast for this capital expenditure to operating expenditure change (and excluded from our capital expenditure forecast) based on the same approach it approved for Jemena Gas Networks. However, it then applied a 15% efficiency adjustment in the operating expenditure model to *both* our reported operating expenditure in 2018 and these newly expensed corporate overheads. In effect, this meant that the draft decision only allowed $10 million per year of these former capital expenditure costs with no analysis to suggest that those capital expenditure costs were inefficient.

In our view, the currently capitalised overhead costs would not have been reduced by the operating expenditure base year efficiency adjustment if they had continued to be capitalised. The AER's economic benchmarking of reported operating expenditure says nothing about the efficiency of those capitalised overheads and it would be inappropriate to assume that they did without further investigation. It is also worth noting that the AER's assessment of our capital expenditure forecasts and Capital Expenditure Sharing Scheme (**CESS**) in the draft decision did not observe any inefficiency in our capital expenditure program.

In our view, an accounting change to treat costs as operating expenditure instead of capital expenditure does not warrant an efficiency adjustment because:

- such an adjustment would not have applied if these were still capitalised, and
- the efficiency benchmarking upon which the adjustment was derived did not treat them as operating expenditure.

2.2.2 Apply only after a realistically achievable transition

Any efficiency adjustment should be rolled in over time in a way that reflects realistically achievable efficiency improvements. This is the intent of JEN's negative $4 million step change approach for savings forecast due to our transformation program.

Where a base year efficiency adjustment is applied, it remains appropriate to provide a glide path as the AER did in its draft decision. The draft decision applied a glide path because the AER recognised that 'it will take time and involve costs for management to implement the required programs over the next regulatory control period.'[44]

As noted above, we propose a $20 million negative step change over the 2021–26 period to capture potential efficiency gains that we could realise from our transformation program. We did not propose a transition for these, but also did not propose a base year efficiency adjustment.

If the AER rejects our proposal and instead adopts an efficiency adjustment materially higher than the $20 million we put forward, then we will need time to realise sustainable opex savings (if these are indeed possible) in a way that does not undermine our service, safety, and reliability outcomes – in which case it would be appropriate for the AER to include a transition like what it included in its draft decision.

[44] AER, *Attachment 6: Operating expenditure | Draft decision – Jemena 2021–26*, September 2020, p.6-47.

3. Trending the base year position

The AER's draft decision largely accepted our approach to the rate of change, however, it made several updates, including:

- slightly reducing the weight applied to labour in the input cost escalation forecast based on a historical industry average labour proportion from 2014–16. This had the effect of increasing the proportion of non-labour costs which do not receive real input cost escalation
- relying only on a labour escalation forecast prepared by DAE rather than averaging it with another forecast, such as that prepared by BIS
- updating the output weights used to apply the output growth forecast to correct for a calculation error included in the analysis underpinning the 2019 (and prior) annual benchmarking report. This outcome places more weight on circuit length and ratcheted maximum demand
- reducing our customer number forecast to reflect reductions in dwelling forecasts published after COVID-19 was declared a pandemic
- reducing the ratcheted maximum demand forecast to reflect AEMO's November 2019 maximum demand forecasts at the transmission connection point, and
- reducing the energy throughput forecast based on JEN's historical average over 2006–18.

These updates, along with the lower base operating expenditure, led to the AER draft decision approving a rate of change that is $20 million lower than we had included in our initial proposal.

Issues with the draft decision

We consider that the draft decision rate of change was understated because:

1. the weight of 59.2%, applied to labour escalation, was outdated because it reflected only data from the 2014–16 period. This does not reflect the most recent industry-wide data. To ensure consistency with other forecasts, more recent data should be used. Data from the 2015–2019 period suggests that the weight should be 68%
2. forecast real labour cost escalation was based only on a forecast developed by DAE. We consider averaging this with an updated forecast from BIS, which now includes the impact of the COVID-19 pandemic and the increase in superannuation guarantee, gives a more balanced forecast
3. it includes the output weights from the MTFP and TLG models when projecting scale escalation – which both suffer from statistical issues, including monotonicity violations and low R^2 values (as discussed above). We recommend the AER not rely on these two models for the purpose of trending the operating expenditure, and
4. forecast energy throughput was based on a 2006–18 historical average – adjusting this to a five-year average that ends with the most recent year of data, 2015–2019, gives a more current starting point that aligns with the concept of using a full five-year regulatory control period as the basis of a forecast. No other inputs into our revised proposal adopt data prior to 2015 given the diminishing usefulness of reflecting future expenses.

Revised proposal

The issues discussed above and our proposed way forward are provided in the next few sections. JEN has updated for the second and fourth of these items in its revised proposal operating expenditure forecast and encourages the AER to also adjust for the first and third in its final decision. For instance, the AER should consider updating the labour weights to reflect more recent data and reconsider its position on including output growth weights from the MTFP and TLG models due to their significant statistical issues.

Adjusting for these issues, our revised proposal operating expenditure forecast includes a higher rate of change that adds $6.4 million more to our operating expenditure allowance in the next regulatory period than that in the AER's draft decision. In developing our operating expenditure trend forecast, we have retained the productivity factor of 0.5% per year, consistent with both our initial proposal and the draft decision.

Table 3–1 sets out our revised proposal for the rate of change forecasts.

Table 3–1: Summary of the revised forecast rate of change ($2021 $M)

	FY22	FY23	FY24	FY25	FY26	Total	AER draft decision	Difference
Input cost trend	0.4	0.7	1.0	1.6	2.4	**6.1**	0.9	5.2
Output growth trend	0.6	1.6	2.8	3.9	5.1	**14.0**	11.8	2.3
Productivity	(0.4)	(0.9)	(1.4)	(1.9)	(2.5)	**(7.1)**	(6.0)	(1.1)
Total operating expenditure trend	**0.6**	**1.4**	**2.4**	**3.6**	**5.0**	**13.0**	**6.6**	**6.4**

3.1 Detailed reasoning on trending

3.1.1 Real input cost escalation

Our revised proposal responds on two key issues related to real input cost escalation:

- **First**, the labour and non-labour weights adopted by the AER – which we consider understate the labour weight
- **Second**, the real labour cost escalation forecast should also factor in forecasts developed by BIS that now account for the impact of the COVID-19 pandemic and the increase in superannuation guarantee.

3.1.1.1 Labour and non-labour weights

The labour weights should reflect the expected efficient labour share over the forecast period, informed by industry-wide data. The draft decision updates the labour and non-labour weights to correct for some errors in the previous values that the AER has used[45]. However, these weights continue to reflect a historical average labour weight across the industry that draws from a sample period that ended in 2016 – this data is outdated.

The more concerning aspect is that the AER has adjusted the 2014–16 data for seven DNSPs[46] out of a total of 13 DNSPs, not included United Energy's data, and only included 2016 data for JEN in deriving this percentage. This percentage is effectively calculated based on four DNSPs' complete data, only partial information from seven DNSPs and no data for one DNSP. This is unlikely to provide a reasonable estimate of the industry-wide weighted average labour proportion.

We previously recommended that the AER update the labour and non-labour weight to reflect more recent RIN data in our submission on the 2020 preliminary benchmarking results.[47] Economic Insights in its 2020 benchmarking report responded that it would only examine the more recent RIN data for the 2021

45 AER, *Draft decision – Jemena 2021–26, Attachment 6: Operating expenditure, September 2020*, p. 52.

46 The AER adjusted the labour cost data for ActewAGL (now Evoenergy), Ausgrid, Endeavour Energy, Energex, Ergon Energy, SA Power Networks, and TasNetworks.

47 Jemena, Letter from Sandeep Kumar to Claire Preston, *Consultation on preliminary 2020 economic benchmarking results*, 9 September 2020.

benchmarking report.[48] However, as this labour weight has an impact on our operating expenditure forecast for the next five years, it needs to be updated in the operating expenditure forecast to reflect more accurate and recent data for its final decision for JEN.

Our concern with using an older average based on incomplete data is that it:

1. is not compliant under the clause 6.5.6(e)(5) (of the NER) requirement that the AER must have regard to the actual and expected operating expenditure of the DNSP during any preceding regulatory control periods because the AER's averaging period only includes the first year of JEN's 2016–20 regulatory control period
2. does not provide a reliable and reasonable estimate for the industry average operating expenditure labour proportion as highlighted above, and
3. is inconsistent with AER's own approach in the draft decision to rely on the DAE forecast only, which was more up to date with COVID-19 impact than BIS.

We consider, there is no NER-based or efficiency justification for the AER retaining an out of date weighting for its final decision. As such, we recommend that the AER update the labour weighting in the final decision to reflect a more recent estimate of what is realistically achievable over the next regulatory period, say, the 68% based on data from 2015–2019 and that this adjustment is incorporated into the AER's final decision.

3.1.1.2 Forecast labour escalation

The final decision should use an average of DAE and BIS labour escalator forecasts, provided that these appropriately reflect the impact of the COVID-19 pandemic and legislated superannuation guarantee increases.

The draft decision only relied on the DAE real labour cost escalation forecast rather than averaging it with the BIS forecast we provided with our initial proposal. Although that was a departure from the AER's standard practice (of using an average), this was understandable given that that BIS forecast:

- was prepared before the COVID-19 pandemic came to light, and
- did not account for the impacts of the legislated superannuation guarantee increases – which DAE had advised the AER should be accounted for as it did in its forecasts.

In response, BIS has updated its forecasts to include the impact of the pandemic and the legislated superannuation guarantee increases. This update—as set out in Attachment 05-02—results in a lower forecast than that we included with our initial proposal. Following this report, BIS has provided a further update to real labour escalation incorporating the AER's latest inflation forecasting approach in its draft position paper,[49] as set out in Attachment 05-03. Our revised proposal adopts the labour escalation forecast set out in Attachment 05-03.

As with our initial proposal and the AER's standard practice, our revised proposal averages the updated BIS forecast with the DAE forecast included in the draft decision. Table 3–2 sets out our revised proposal for forecast real labour cost escalators.

Table 3–2: Proposed real labour cost escalators (per cent)

		FY22	FY23	FY24	FY25	FY26
DAE with increase in superannuation increase	[1]	0.24%	(0.25%)	(0.07%)	0.37%	1.00%

48 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 DNSP Annual Benchmarking Report*, 13 October 2020, pp. 11–12.

49 AER, *Draft position – Regulatory treatment of inflation*, October 2020.

		FY22	FY23	FY24	FY25	FY26
BIS without increase in superannuation guarantee	[2]	0.81%	0.74%	0.88%	1.12%	1.12%
Increase in superannuation guarantee	[3]	0.50%	0.50%	0.50%	0.50%	0.50%
BIS with increase in superannuation increase	[4]=[2]+[3]	0.98%[50]	1.24%	1.38%	1.62%	1.62%
Average	**[5]=([1]+[4])/2**	**0.61%**	**0.50%**	**0.65%**	**0.99%**	**1.31%**

3.1.2 Output growth

Our revised proposal responds to two key issues related to output growth:

- **First**, the output weights adopted by the AER. We are concerned with the use of MTFP and translog models although we have adopted the AER's method in our revised proposal
- **Second**, the energy throughput forecasts appear understated because they are based on an historical average from the 2006–18 period–we have replaced it with an historical average from 2015–19. We have also updated the starting point of the customer number forecast to reflect our re-stated customer numbers in our Economic Benchmarking RIN response submitted to the AER in September 2020.[51] We have retained the AER's customer number growth rate from the draft decision.

3.1.2.1 Output weights

Apart from the model reliability issues highlighted in section 2.1.2 and 2.1.5 above, our main concerns with using output weights from the operating expenditure MPFP and translog models to trend operating expenditure, are:

1. **MTFP/MPFP output weights reflect drivers of the total cost but not operating expenditure**.

   The AER's consultant, Economic Insights, noted in its 2020 benchmarking report that the operating expenditure MPFP output weights may differ from operating expenditure econometric models as that model represents the relationship between outputs and total cost rather than operating expenditure.[52] However, CEPA considers that for the purpose of operating expenditure trending, it is inappropriate to use the output weights reflecting total cost.[53]

2. **The Australian sample mean of translog models, especially LSE TL, gives unreasonable estimates**.

   CEPA expressed concerns in its report that the output weights for the LSE TL model are significantly different from all other models with the same specifications.[54] As shown in Table 3–4, the weight on customer numbers in the LSE TL model is 20% lower than all other models and the weight on ratcheted maximum demand in that model is 24% higher than the rest.

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50 As noted in the operating expenditure forecast model (Attachment 05-01), we have adjusted the BIS real labour escalator forecast for 2021-22 to reflect 9 months, rather than 12. That is, 0.98% = (1+ 0.81% + 0.50%)^(9/12) – 1. This aligns with other escalation inputs included in the model.

51 Jemena Electricity Networks, *2019 – Economic Benchmarking RIN – Templates (updated 25 October 2020)*, October 2020. See the '3. 4 Operational data' sheet.

52 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 DNSP Annual Benchmarking Report*, 13 October 2020, Pg. 5.

53 CEPA, *The Australian Energy Regulator's operating expenditure benchmarking – a review of the impact of capitalisation and model reliability*, 13 November 2020, Pg. 27.

54 CEPA, *The Australian Energy Regulator's operating expenditure benchmarking – a review of the impact of capitalisation and model reliability*, 13 November 2020, Pg. 20.

Table 3–3: Output weights applied in the AER's draft decision (per cent)

	LSECD	LSETLG	SFACD	SFATLG
Customer numbers	68.95%	37.95%	67.43%	69.73%
Circuit length	15.56%	21.16%	15.08%	12.37%
Ratcheted maximum demand	15.48%	40.89%	17.50%	17.90%

We understand from the AER that it may adopt the output weights from the full sample mean in the final decision. Although we have concerns with the reliability of the translog models, if the AER were to continue relying on them, then we encourage it to adopt the full sample mean instead of the Australian sub-sample mean.

Stepping back from the technical econometric detail, the importance of ratcheted maximum demand as an operating expenditure growth driver will reduce over time – and, therefore, its importance as an output measure – as electricity networks increasingly support two-way flows of electricity.

To this end, the definition of 'regulated services' is currently being reviewed by the AEMC[55] to specifically reflect that:

- networks are increasingly providing two-way flows for our customers with DER, and
- these two-way flows will benefit all customers – both with and without DER – by providing benefits including new lower cost network support and bulk power system strength services and by providing low marginal cost energy into the wholesale market.

This recognised change in the scope of our services reflects the broad network service expectations of our People's Panel[56] and will necessarily require the AER to review its output measures in future.

For now, the number of customers is most likely the closest available proxy to reflect DER on our network in the AER's benchmarking modelling. Absent an alternative DER-related output measure, as DER penetration increases, we would expect the importance of that proxy to increase (i.e. with a higher weight).

This trend should inform the AER's choice of output model weights in its final decision. In particular, the AER should recognise that most of the output weights from the five models it considers are estimated using data over a long historical period. As such, it will unlikely pick up more recent changes to the relative importance of different output measures (or cost drivers), particularly in relation to DER penetration on our network, which has grown rapidly in a short period of time.

As DER becomes increasingly integrated into our service offering and the proportion of expenditure driven by maximum demand continues to decrease over time (as new drivers such as DER become more relevant), the resulting increases in cost are unlikely to be captured by the relatively flat peak demand output measure. Therefore, the consequence of increasing the output weight to ratcheted maximum demand is that it would underestimate the cost to meet this important evolution in our customers' expectations and the services we provide through the rate of change.

In our view, dropping the output weights from the MTFP and translog models better aligns with this trend. Although we have not dropped the weights from the MTFP and translog models in our revised proposal operating expenditure forecast, we encourage the AER to do so in its final decision for JEN.

55 AEMC, *Distributed energy resources integration – updating regulatory arrangements*, 30 July 2020.

56 JEN, *2021-26 Electricity Distribution Price Review, Regulatory Proposal, Attachment 02-02, Community consultation report*, 31 January 2020, Pg. 4, recommendation number 4.

3.1.2.2 Output forecasts

Our proposed customer number and energy throughput forecasts are higher than those included in the draft decision.

Regarding customer numbers, we have adopted the AER's draft decision growth rate. However, as we restated our actual customer numbers in September 2020, it subsequently impacts the estimated customer numbers over the next regulatory period. As such, this update had no impact on the rate of change forecast.

With regards to energy throughput, we retained the estimate for 2020–21 adopted in the draft decision but replaced the growth rate applying from that point forward over the next regulatory period. In particular, we replaced the annual cumulative growth rate calculated using data over the 2006–18 period that was included in the draft decision with a slightly higher growth rate calculated using data over the 2015–19 period.[57] In our view, it is more appropriate to use a more recent average that reflects a five-year period (i.e. the length of the next regulatory period) rather than an older and longer average, because the recent trend in energy efficiency is likely to persist into the future and because a once-off structural change to the customer which we serve[58] is not expected to continue going forward.[59]

Table 3–4 sets out our revised proposal output growth forecasts.

Table 3–4: Revised proposal output growth forecasts (per cent)

	FY22	FY23	FY24	FY25	FY26	Cumulative
Customer numbers (#)	0.65%	1.11%	1.42%	1.41%	1.39%	**6.13%**
Circuit length (km)	1.33%	1.91%	1.86%	1.73%	1.67%	**8.80%**
Ratcheted maximum demand (MW)	-	-	-	-	-	**0%**
Energy throughput (GWh)	0.33%	0.45%	0.45%	0.45%	0.45%	**2.14%**

57 The AER draft decision included a cumulative annual growth rate of negative -0.13839021600166% in 2021-22 and -0.184477761028035% over 2022–26. Our revised proposal includes a cumulative annual growth rate of 0.446380862394302%.

58 Through the 2011-15 regulatory period, JEN's energy throughput incurred a significant decline as industrial customers declined significantly through structural change.

59 Refer to our Appendix A of our overview document that outlines specific government incentives designed to abate reductions, and in fact increase, industrial and manufacturing programs.

4. Specific forecast position

We proposed three specific forecasts in our initial proposal, and the AER's draft decision accepted two of these, namely: GSL payments and DRC.

However, the AER rejected the third – being our proposal to treat the ESV levy as a specific forecast, or to otherwise include the increase in that levy in our operating expenditure forecast or allowed annual pricing adjustments. Although it acknowledged the increase in this levy, the draft decision stated that we should manage it within our existing base operating expenditure.

In our view, this draft decision does not afford us an opportunity to recover the efficient cost of this regulatory obligation. In response, we have included further information to support its inclusion, or otherwise seek recovery through other mechanisms.

Our revised proposal for specific forecasts is set out in Table 4–1. It includes the three specific forecasts we had initially proposed, which have been updated for the revised proposal.

Table 4–1: Summary of the revised specific forecasts ($2021 $M)

	FY22	FY23	FY24	FY25	FY26	Total
GSL payments (AER draft decision amount)	0.2	0.2	0.2	0.2	0.2	0.9
Electricity Levy for Energy Safe Victoria	1.4	1.4	1.4	1.4	1.4	6.8
DRC	0.8	0.8	0.8	0.8	0.8	4.0
Total	**2.3**	**2.3**	**2.4**	**2.4**	**2.4**	**11.8**

4.1 Detailed reasoning

4.1.1 GSL payments

The draft decision accepted our specific forecast for GSL payments. In doing so, the AER:

- increased the forecast slightly to reflect the historical average GSL payments made by JEN over the 2015–19 period rather than just the 2018 base year (as we had proposed) – we have adopted this update in our revised forecasts
- noted that the Essential Services Commission of Victoria (**ESCV**) was reviewing its GSL scheme as part of a wider consumer protection framework review and that the outcome of that (now completed) review should be reflected in the operating expenditure forecast – we agree and have done so in our revised forecasts.

The ESCV's review of the Victorian consumer protection framework in the Electricity Distribution Code – including the GSL scheme – will affect the administration of the GSL scheme in the coming regulatory period. Consultation on the ESCV's draft decision closed in July 2020, and the final decision was released in November 2020.

The AER's draft decision noted that its final decision will account for the outcome of this ESCV review (i.e. where it changes the amounts that JEN is required to pay customers under the scheme) provided that review is completed ahead of the AER's final decision.

We have reviewed the ESCV's final decision on its EDC review and our analysis shows that although the payment amounts and volume of payments are both expected to increase, the overall increase in costs (relative to the draft decision) is likely to be immaterial. We consider that this increase can be managed within the allowance approved in the draft decision. As such, we have adopted the draft decision specific forecast for GSL payments.

4.1.2 Electricity Levy for ESV

The electricity levy is used to cover the ESV's activities related to regulating the Victorian DNSPs. Consistent with JEN's proposal and evidence, the AER's draft decision acknowledges that this levy has increased between 2018 and 2019 and that such increases are beyond JEN's control.

Notwithstanding this acknowledgment, the AER has provided no category specific forecast for this levy. Instead, it concluded that the costs in JEN's 2018 base year and the forecast rate of change should be sufficient and that JEN should manage these variations in the mandated ESV levy within the year to year variations across our cost base.

JEN had also proposed—as an alternative—to include this levy within the B factor term of the price control mechanism for standard control services. Such an approach is consistent with that currently employed in Victoria for recovering annual distribution licence fees payable to the ESCV. AusNet Services also proposed this approach. However, the draft decision did not adopt this alternative approach either. We request that the AER reconsiders its position on this matter, noting that:

- The acknowledged cost increase in the ESV levy is unavoidable for Victorian DNSPs
- Yet, the increase is not currently reflected in our current cost base (or as adjusted by the AER in the draft decision), nor in the trend components of our operating expenditure forecast.

This leads to a mismatch between efficient costs and the draft allowed costs as these costs:

- are necessarily incurred as a licence requirement
- are uncontrollable—we have no avenues to negotiate a different outcome with the vendor
- are supported by written evidence on the legitimacy of the cost increase, giving certainty about the magnitude of the change.

Given these facts, it should be clear to the AER that these costs are beyond our control and that JEN will necessarily incur them. Our revised proposal operating expenditure forecast therefore includes a specific forecast that reflects the increased ESV levy costs.

In our view, this is a correct application of the forecast operating expenditure NER, where:

- **clause 6.5.6(a)(2)** requires that our forecast include the costs needed to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services – paying the ESV levy is a licence obligation and JEN has provided the best forecast of complying with that obligation as this clause requires, and
- **clause 6.5.6(c)** explains the circumstances under which the AER *must* approve our operating expenditure forecast – these require efficiency and prudence and a realistic expectation of demand and costs. The AER's draft decision statements about the nature of these costs acknowledge that all these criteria are met for this mandated levy. Yet, it applied a materiality overlay (termed "exceptional circumstances" in the draft decision) to our permitted cost recovery that appears to have no basis in the NER.

Given this, it is appropriate that the AER reconsider the issue.

Irrespective of the cost recovery mechanism (options include a specific forecast, an operating expenditure step change or annual pricing pass through consistent with the ESCV licence fee), the final decision must ensure these efficient, unavoidable and uncontrollable costs are funded for Victorian DNSPs, including JEN.

4.1.3 Debt raising costs

The AER's draft decision used the same assumptions and approach to calculate DRC that we included in our initial proposal. The draft decision approved a slightly lower DRC forecast than we proposed because its forecast applied the method to a slightly lower projected RAB over the next regulatory period than we had proposed.

We have retained these same approved assumptions and approach in our revised proposal operating expenditure forecast. We understand the AER will update the forecast DRC to reflect its final decision capital expenditure allowance.

5. Step changes

The AER's draft decision approves step changes totalling $32 million over the next regulatory period, this is less than the $42 million we proposed in our initial proposal. This outcome reflects the AER's draft decision to:

- allow for three of the seven positive step changes we proposed, and
- adopt a base year efficiency adjustment instead of the $20 million negative step change we proposed in our updated proposal for savings arising from our transformation program.[60]

For each of the three approved step changes, the draft decision requested additional information from us in our revised proposal to assess any changes that might impact the AER's final decision. The additional information is provided below and in the supporting attachments.

We adopted the AER's draft decision to not approve our proposed step changes for other costs arising from: our Future Grid program, the transitional return on debt alignment costs, Environment Protection Act changes, and additional RIN reporting requirements as outlined in our initial proposal. Further, we have not incorporated any additional step changes at this stage of the revised proposal process. However, as explained in section 6, we strongly recommend that the AER incorporate into the final decision an allowance for other costs expected over the next regulatory period due to changes in regulatory obligations.

Our revised proposal operating expenditure forecast for step changes are outlined in Table 5–1.

Table 5–1: Summary of the revised step changes ($2021 $M)

	FY22	FY23	FY24	FY25	FY26	Total	Draft decision	Difference
Insurance premiums	3.9	5.0	6.0	6.4	6.9	**28.2**	28.2	-
REFCL compliance	-	0.0	0.4	0.4	0.4	**1.3**	1.3	0.1
Cybersecurity	0.6	0.6	0.6	0.6	0.6	**2.9**	2.9	-
Total	**4.4**	**5.6**	**7.0**	**7.4**	**7.9**	**32.4**	**32.4**	**0.1**

5.1 Insurance premiums

We welcome the AER's acceptance of our step change for increases in public lability insurance premiums. We appreciate that the AER (and the customer challenge panel (sub-panel 17)) recognise that these costs are prudent, will have a material impact on our operating expenditure and reflect increases in costs beyond our control.

We have retained this step change forecast in our revised proposal. We note that the draft decision asked that we provide updated information relating to our September 2020 insurance premium renewal in our revised proposal. Consistent with the AER's request, we provide further information to demonstrate that the changes we included our initial proposal to occur—that is, the conditions in the insurance market would continue to be more difficult—have in fact, arisen.

In particular:

- our actual annual premiums incurred in September 2020 are closely aligned with those forecast in our initial proposal
- as expected:
  - insurance markets have tightened as was outlined in our initial proposal

[60] Our proactive negative step change and the AER's glide path (transition cost) step change is discussed in section 2 above.

− the extent of coverage has contracted.

This is corroborated by the further information included in Attachment 05-04.

Based on this more recent information, the step change for insurance premiums that we proposed in our initial proposal and accepted by the AER in their draft decision remains appropriate. Consequently, we have retained this step change in our revised proposal operating expenditure forecast.

5.2 REFCL compliance

We welcome the AER's acceptance of our need to incur additional costs to comply with our new obligations under the Electricity Safety (Bushfire Mitigation) Amendment Regulations (2016) (and other related instruments)[61] for testing and maintaining installed REFCLs.[62]

These obligations will have an unavoidable financial impact on our business and are critical to the safe, secure, and compliant operation of our network.

5.2.1 Requirements

5.2.1.1 Coolaroo zone substation

Since submitting this step change in our initial proposal, we have made substantial changes to our approach to complying with our obligations for the Coolaroo zone substation. These changes result from JEN being provided with an exemption under the Electricity Safety Act 1998—as foreshadowed in our initial proposal[63]—which will allow us to implement a technical solution that has a lower capital cost while still providing a commensurate reduction in bushfire ignition risk.

In the interest of transparency, we informed the AER and stakeholders of this continued development in our initial proposal and in our engagement throughout 2020. The exemption allows us to implement the most efficient solution for the long-term benefit of our customers.

5.2.1.2 Kalkallo zone substation

Separately—and following further technical assessment and a change in AusNet Services' proposed compliance approach for its Kalkallo zone substation (which supplies three JEN feeders, one of which must be REFCL-protected[64])—we must also now undertake additional works to install a 'remote REFCL' on JEN's KLO22 overhead feeder to comply with its regulatory obligations.[65]

ESV has provided clarification of JEN's regulatory obligations in relation to our Kalkallo feeders[66] and acknowledged our proposed approach to achieving compliance.[67] Our compliance approaches in relation to both Coolaroo and Kalkallo are described in more detail in Attachment 04-01.

5.2.1.3 Estimated costs

The draft decision requested that our revised proposal step change forecast account for the outcome of our Coolaroo exemption application. The results of this application have been reflected in our updated step change

61 Including the Electricity Safety Act 1998 and the Electricity Safety (Bushfire Mitigation) Regulations 2013.

62 AER, *Attachment 6: Operating expenditure | Draft decision – Jemena 2021–26*, September 2020, p. 6-62.

63 JEN, *2021-26 Electricity Distribution Price Review Regulatory Proposal – Attachment 05-01 – Forecast capital expenditure*, 31 January 2020, pp. 89-90.

64 As explained further in Attachment 04-01, two of JEN's Kalkallo feeders do not require REFCL protection as they are fully underground.

65 Relevantly for the KLO22 overhead feeder, the Electricity Safety (Bushfire Mitigation) Regulations 2013, Reg. 7(1) (ha) and (hb).

66 ESV, *ESV Position Paper: Multiple Ownership of Polyphase Electric Lines and Complying Substations*, 21 August 2020.

67 ESV letter to JEN, *RE: Strategy to meeting bushfire mitigation regulations – KLO22*, 25 September 2020.

forecast. Additionally, our updated step change forecast also accounts for the necessary changes to our compliance approach for feeders emanating from AusNet Services' Kalkallo Zone substation.

Although JEN has received an exemption in relation to arrangements at Coolaroo zone substation (effectively relating to REFCL construction obligations), we have not received any exemption relating to the ongoing annual testing obligations which form part of this step change forecast. JEN's step change forecast covers the mandatory annual testing activities on four feeders—three originating from Coolaroo and one from Kalkallo.

We have not sought an exemption to test only one of the three Coolaroo feeders annually, as we anticipate that the significant growth occurring in the Coolaroo supply area will result in at least minor feeder reconfiguration or modification works on these feeders each year, following which testing would need to be conducted to ensure JEN remained compliant with its REFCL obligations.

In this revised proposal, we submit an updated operating expenditure step change of $1 million ($2021). This is $0.1 million ($2021) less than outlined in our initial proposal.

Further details on this step change estimate are contained in Attachment 05-06.

5.3 Cybersecurity

We welcome the AER's acceptance of our step change to lift our capability to detect and respond to cyber security incidents in accordance with the Australian Energy Sector Cyber Security Framework. These standards will have a material financial impact on our business.

We have retained the step change forecast approved in the draft decision in our revised proposal operating expenditure forecast.

Since submitting our initial proposal, our observations around cyber-security obligations and actual cyber-crime activity have only grown more acute. For instance:

- the Australian Government has:
  - affirmed its plans for further cyber security obligations through the release of its cyber security strategy[68]
  - established an industry advisory committee to strengthen protecting Australian interests against cybercrime,[69] and
  - consulted on the approach to protecting critical infrastructure and systems of national significance[70]—which apply directly to JEN
- the rate of cyber-attacks has grown, which has been driven by the COVID-19 pandemic. This has been reported by the Australian Signals directorate who state "*with impacts sharpened as a result of the COVID-19 pandemic.*"[71]

We consider the step change continues to be appropriate in this revised proposal.

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68 Australian Government, *Australia's cyber security strategy 2020*, 6 August 2020.

69 The Hon Peter Dutton MP, Minister for Home Affairs, *New Industry Advisory Committee to support the delivery of National Cyber Security priorities*, 20 October 2020.

70 The Australian Government, Department of Home Affairs, *Protecting Critical Infrastructure and Systems of National Significance*, August 2020.

71 Australian Signals Directorate, *Annual Report 2019–20*, 12 October 2020. Pg. 11.

6. Other costs not included in our forecast

Our revised proposal operating expenditure is lower than our likely efficient costs because it does not include various costs that we expect to incur.[72] To the extent that these costs, or any components of our revised proposal are not adopted in its final decision, then the operating expenditure allowance will fall below that needed to operate JEN's electricity distribution network efficiently.

Up until this point in the price review process, several changes have arisen that will impact our actual expenditure during the next regulatory period; however, these items will not be picked up in the base, step and trend method commonly applied by the AER.

We recommend that the AER incorporate these additional costs into its final decision for JEN, or considers them in the development of an overall alternative operating expenditure forecast.

6.1 Which costs were not included?

Table 6–1 describes these additional items and explains why they were not included in the revised proposal operating expenditure forecast. The fact that they are not included in our proposal does not mean that they should not form a part of the AER's considerations, especially in the circumstances where the AER has a degree of discretion in forming its view.

The estimated total cost of these activities is greater than $1.0 million – which is not an unsubstantial amount of money for a business the size of JEN.

We have not identified any negative step changes.

Table 6–1: Other costs

Description	Why they were not included	Approximate cost over the next regulatory period
Incremental RIN reporting	The AER acknowledged these costs in its draft decision, however disallowed a step change based on a materiality consideration. We: • disagree that materiality is a criterion set out in the NER when considering forecast operating expenditure—the NER only requires that the expenditure is efficient. • consider that the costs are efficient and necessarily incurrent to meet our obligations.	$500,000
Electricity Safety (Registration and Licensing) Regulations 2020. This new regulation requires our line workers to undertake additional training.	Consistent with the materiality threshold requirement the AER adopted when disallowing the *incremental RIN reporting*, we have not raised this additional incremental cost. Despite this, and for reasons outlined against the *incremental RIN reporting* expenditure item noted in this table, we consider the AER should consider these costs in its final decision.	$356,920

[72] In this chapter we are only focusing on explicit costs link to regulatory obligations. For various other reasons, our revised proposal operating expenditure forecast is also likely to be understated. For instance, we recommend various updates to how the AER applies its rate of change in chapter 3, which we have not included (e.g. updating the labour escalation and output growth weights).

Description	Why they were not included	Approximate cost over the next regulatory period
Electric line clearance obligations – In its draft decision, the AER noted forthcoming changes to electric line clearance regulations which may lead to immaterial reductions in costs.[73] Pursuant to our obligations under clause 6.6.1(f) of the NER for negative step changes we considered the change and determined that there was no negative change amount.	There is not a negative step change for this change in obligations to report. Although the *Electricity Safety (Electric Line Clearance) Regulations 2020* provide for minor changes to the available exceptions to minimum clearance space obligations, JEN does not rely on these exceptions. Reliance on these exceptions is conditional upon additional inspection activities being undertaken, which would result in a higher overall vegetation management cost to JEN. Given this, our current practices for meeting these obligations is the most efficient approach.	$0
Total		**$856,920**

6.2 Why these costs are not captured elsewhere?

Based on the draft decision, we are concerned that the costs outlined in section 6.1 would not be picked up in the base, step and trend method applied by the AER because individually the changes are considered immaterial or too uncertain, or because they have arisen too late in the process. Yet, collectively they comprise a significant amount, they are unavoidable and will necessarily be incurred to meet JEN's licence conditions and other regulatory obligations.

The costs will not be recovered in the other components of the base, step, and trend method for forecasting operating expenditure because:

- they have not been incurred in our base year
- the labour escalation and scale components of the rate of change relate to changes in labour costs or network growth, not changes in regulatory obligations
- The productivity factor, which the AER described–when determining the industry-wide value of 0.5% per year–as:[74]

  > *This productivity growth factor captures the improvements in good industry practice that should be implemented by efficient distributors as part of business-as-usual operations. Another way of putting this is that it reflects the improvement in the efficient production frontier within the electricity distribution industry. This comes from such things as new technology, changes to management practices and other factors that contribute to improved productivity within the industry over time.*

  Nowhere in the AER's consideration on productivity was changes in regulatory obligations mentioned.

In our experience, the cost impost of regulatory obligations tends to increase over time; we cannot identify any decreases in regulatory obligations, and even if some were identified, we would need to disclose them through our cost pass-through obligations NER clause 6.6.1(f), in full as there is not materiality threshold for negative cost changes. Because of this obligation and because obligations only ever increase, it should not come as a

73 AER, *Attachment 6: Operating expenditure | Draft decision – Jemena 2021–26*, September 2020, p. 6-72.

74 AER, *Final decision paper – Forecasting productivity growth for electricity distributors*, March 2019, p. 7. The paper went on to explain that it had explicitly adopted a zero productivity factor in prior determinations rather than the negative trend observed previously because those trends were largely attributable to an increase in costs required to meet significant new regulatory obligations. The AER said that the zero-productivity factor was adopted in the absence of new regulatory obligations.

surprise that there are no negative step changes included in this revised proposal. The items listed in Table 6–1 are an example of this; albeit a subset of those that are likely to arise over the next regulatory period.

Although we have access to the cost pass-through mechanisms in the NER for positive cost increases, the expected values of these items individually are unlikely to meet the materially threshold criteria–and, therefore, we will be prevented from recovering these costs via cost pass-through within the regulatory period.