Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review Regulatory Proposal

Revocation and substitution submission

1 January 2016 - 31 December 2020

Public

6 January 2016

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ABBREVIATIONS

2016 regulatory period	the period 1 January 2016 to 31 December 2020
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
April 2015 proposal	JEN's regulatory proposal submitted to the AER in April 2015
ARORO	Allowed Rate of Return Objective
ARR	Annual Revenue Requirement
augex	Augmentation Capital Expenditure
CESS	Capital Expenditure Sharing Scheme
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DMIA	Demand Management Incentive Allowance
DMIS	Demand Management Incentive Scheme
DRP	Debt Risk Premium
EBSS	Efficiency Benefit Sharing Scheme
EDPR	Electricity Distribution Price Review
ESV	Energy Safe Victoria
F&A	AER *Final framework and approach for the Victorian Electricity Distributors – Regulatory control period commencing 1 January 2016*, October 2014
GSL	Guaranteed Service Level
ICT	Information and Communications Technology
JEN	Jemena Electricity Networks (Vic) Ltd
kW	Kilowatts
MAR	Maximum Allowed Revenues
MRP	Market Risk Premium
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electricity Rules
NPV	Net Present Value
OMR	Operation, Maintenance, and Replacement
Optimal NEO Position	The position which contributes to the achievement of the NEO to the greatest degree and best promotes the long term interests of consumers of electricity
Preliminary decision	The AER's preliminary decision released on 29 October 2015
PTRM	Post Tax Revenue Model
RAB	Regulatory Asset Base
REFCL	Rapid Earth Fault Current Limiter

RIN	Regulatory Information Notice
SCS	Standard Control Services
STPIS	Service Target Performance Incentive Scheme
submission	JEN's Submission to the AER on the Revocation and Substitution
Tribunal	Australian Competition Tribunal
TSS	Tariff Structure Statement
WACC	Weighted Average Cost of Capital

EXECUTIVE SUMMARY

1. Jemena Electricity Networks (Vic) Ltd (**JEN**) owns and operates the electricity network that safely, reliably and affordably services over 319,000 homes and businesses across north west Melbourne—from Mickleham to Footscray, and Gisborne South to Ivanhoe. We also own, maintain and read the meters that allow retailers to bill our smaller customers for their electricity usage, and provide them with information to help them better manage this usage. Our customers, stakeholders and community depend on our service performance every day to enhance their lifestyle and support their businesses.

2. We have developed a detailed submission to the Australian Energy Regulator (**AER**) on the revocation and substitution (**submission**) for the period 1 January 2016 to 31 December 2020 (the **2016 regulatory period**). This submission sets out the revenues required to operate and maintain our network and the incentive and risk management framework necessary during the 2016 regulatory period to contribute effectively to achieving the National Electricity Objective (**NEO**) and best promote the long term interests of consumers of electricity (the **Optimal NEO Position**).

3. To develop this submission we reviewed the AER's preliminary decision[1] (**preliminary decision**)—including both the overall and the constituent decisions—and analysed the material changes that have occurred in the energy market subsequent to JEN's regulatory proposal being submitted to the AER in April 2015 (**April 2015 proposal**). We then re-engaged with our customers and stakeholders to confirm their priorities and preferences for the 2016 regulatory period, and sought expert advice to assist us in forming a view on the extent to which the preliminary decision promotes the Optimal NEO Position.

4. We welcome the preliminary decision's recognition of our responsiveness to the incentives of the regulatory regime and our provision of high levels of service performance levels in an efficient manner. We also welcome the preliminary decision's recognition that additional investment is required to maintain the network service levels that customers value, and to meet growth in fast growing parts of our network. Finally we welcome the preliminary decision's recognition of our customer and stakeholder engagement in developing our April 2015 proposal. However, we are concerned that the preliminary decision rejects aspects of our April 2015 proposal such that the preliminary decision will not promote the Optimal NEO Position.

5. Our submission ensures we have the incentives and funding to invest, operate and maintain a safe, reliable and responsive distribution network, including the provision of a metering service which is valued by our existing and new customers. At the same time, our submission ensures that we have the incentives to continually improve our cost efficiency and share these improvements with our customers over time. Importantly our submission also enables us to adapt our services to the changing energy market. The key elements of our submission are:

   - Forecast operating expenditure that reflects our efficiency and our responsiveness to the incentives of the regulatory regime, as well as changes in our operating environment, including new safety and reporting obligations, and customer willingness to consult and support vulnerable customers
   - Targeted investments to maintain our current service levels across the network—including in new growth areas, in established areas where assets are ageing, and in IT systems to support the services our customers have told us they value
   - Lower funding costs that reflect easing market conditions after heightened perceptions of risk during the global financial crisis and how we propose to share these lower funding costs with our customers
   - An incentive framework that continues to be aligned with our customers' interests, including the capital expenditure sharing scheme and demand management incentive scheme continuing to incentivise service reliability improvement and strengthen incentives for investment in demand management

[1] The regulatory decision with respect to JEN made by the AER in accordance with NER cl. 11.60.3, released on 29 October 2015.

- A risk management framework that balances the cost sharing associated with low frequency, high value events between us and our customers.

6. We are confident that our submission promotes the Optimal NEO Position. In this submission we have sought to highlight those elements:

- Of the preliminary decision where the AER agrees that our April 2015 proposal promotes the Optimal NEO Position
- Where we have incorporated aspects of the preliminary decision into our submission whilst maintaining aspects of our April 2015 proposal
- Of our April 2015 proposal where updated information—including updates to model inputs—promotes the Optimal NEO Position
- Where we have provided further information to demonstrate that the preliminary decision does not promote the Optimal NEO Position—and the position set out in our April 2015 proposal is maintained.

REVENUE REQUIRED TO PROVIDE THE SERVICES OUR CUSTOMERS VALUE

7. Our submission sets out the revenues ($2015) required to operate and maintain our network over the 2016 regulatory period. This includes a total of:

- $1,430m in revenues to provide our distribution services[2] over the 2016 regulatory period, $122m more than our April 2015 proposal (see Table OV–1)
- $173m in revenues to provide our alternative control metering services[3] over the 2016 regulatory period, $15m more than our April 2015 proposal (see Table OV–2)

Table OV–1: Annual revenue requirement ('building block' costs) for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total	NPV
April 2015 proposal	249.27	250.77	271.02	264.31	272.32	**1,307.70**	**1,144.38**
Preliminary decision	220.94	199.08	216.99	222.62	222.70	**1,082.34**	**978.49**
This submission	289.05	264.83	292.29	292.90	290.77	**1,429.85**	**1,199.23**

Table OV–2: Annual revenue requirement ('building block' costs) for metering services ($2015, $millions)

	2016	2017	2018	2019	2020	Total	NPV
April 2015 proposal	42.16	31.12	31.62	27.39	25.59	**157.88**	**139.89**
Preliminary decision	44.85	43.37	38.26	39.59	38.91	**204.97**	**185.94**
This submission	38.07	36.86	32.63	33.34	32.35	**173.24**	**146.21**

2 Known as Standard Control Services (**SCS**) in the NER.

3 These constitute metering services provided in the previous 2011 regulatory period under the cost recovery order in council and unclassified by the AER.

LOWER NETWORK BILLS FOR RESIDENTIAL CUSTOMERS BUT HIGHER NETWORK BILLS FOR BUSINESS CUSTOMERS

8. Our submission includes maintaining the service levels that our customers value and responding to changes in our operating environment and customer preferences and will result in a:

- Modest increase in our charges for our distribution services over the 2016 regulatory period as the impact on our revenue requirements of the additional capital expenditure and operating expenditure required to provide our distribution services outweighs the impact of reductions in our funding costs
- Significant decreases in our charges for our metering services over the 2016 regulatory period as the reduction in our funding costs and capital expenditure to provide our metering services results in a lower revenue requirement for metering services.

9. While the decrease in our charges for our metering services over the 2016 regulatory period benefits all customers, Figure OV–1 highlights that typical:

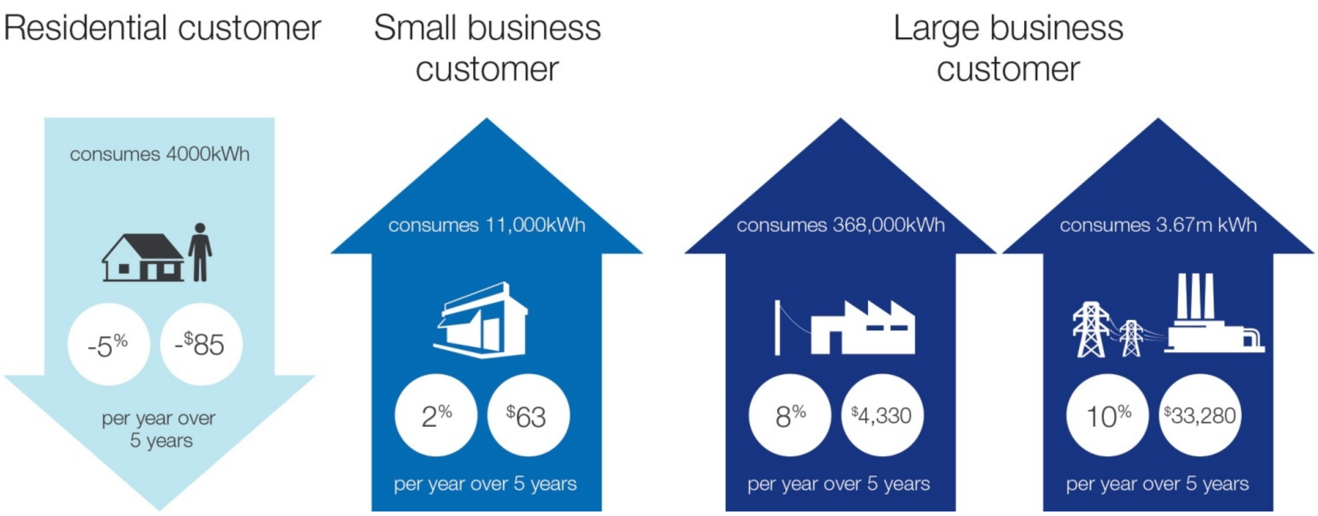
- Residential customers will receive a reduction in their annual network charges of $76 (or a reduction of 5% in their end-retail bill) over the period (excluding the impact of inflation),
- Small business customers will receive an increase in their annual network charges of $73 (or an increase of 2% in their end-retail bill) over the period (excluding the impact of inflation),
- Large low voltage business customers will receive an increase in their annual network charges of $4,330 (or an increase of 8% in their end-retail bill) over the period (excluding the impact of inflation),

10. As flagged in our April 2015 proposal and included in our 25 September 2015 Tariff Structure Statement submission[4] (**TSS**), we are proposing to offer a new 'maximum demand charge' from 1 January 2018 to residential and small business customers. This new tariff provides residential and small business customers with a new way to save on their electricity bills and is intended to encourage customers to make decisions about using the network that takes better account of the costs involved. This new charge will mean that over the next 5 years, how much customers pay for using our network may increasingly depend on how and when they use the network—that is, on their maximum demand in kilowatts (**kW**) during the specified period of 3pm to 9pm on work days (excluding public holidays). However, as requested by the Victorian Government, customers can choose if they want to take up electricity offers that adopt this new way of pricing.

11. We will work with our stakeholders–including retailers, customer representatives and the Victorian Government–to maximise the benefits of the targeted investments we are proposing to empower customers to take control of their energy needs.

[4] JEN, *Tariff Structure Statement*, September 2015.

Figure OV–1: Indicative changes in annual bills over the 5-year period for typical customer (excluding inflation)



THE PRELIMINARY DECISION

12. The preliminary decision notes that in making an overall decision the AER has made a number of constituent decisions. The elements of the preliminary decisions can be categorised as:

- Accepts that many aspects of our April 2015 proposal—such as the efficiency of our operating expenditure and the need for increased capital expenditure to replace and augment parts of our network—promote the Optimal NEO Position, and we welcome these aspects of the preliminary decision.
- Seeks further information on aspects on our April 2015 proposal—such as on the prudence and efficiency of the targeted investments we plan to make to maintain our current service levels in new growth areas—or suggests minor changes to aspects of our proposal—such as on the roll-forward of the Regulatory Asset Base (**RAB**).
- Rejects aspects of our April 2015 proposal—such as the changes in our operating environment and the need for increased operating expenditure to meet these changes, the continuation of an incentive framework that remains aligned to our customers' interests for service improvements and demand management, and the benchmark funding costs that network businesses such as JEN require to invest in the services that our customers value.

13. We welcome the preliminary decision's recognition of our efficiency in providing levels of service that our customers value. We also welcome the preliminary decision's recognition that additional investment is required to maintain the network service levels that customers value, and to meet growth in fast growing parts of the area serviced by our network.

14. However we are concerned that in a number of areas, the preliminary decision does not provide a reasonable opportunity for us to recover the efficient costs we expect to incur over the 2016 regulatory period in providing services to customers and complying with our regulatory obligations. In particular:

- The allowed return on equity is below the level required to promote efficient investment in our network for the long-term interests of customers. The allowed return on equity does not reflect prevailing conditions in the market for equity funds, and does not adequately compensate investors for the risks faced in providing funds for network investment. The shortfall in the allowed return on equity is approximately $85m over the 2016 regulatory period.

- The allowed return on debt is not sufficient to cover efficient debt financing costs. The shortfall in the allowed return on debt is approximately $10m over the 2016 regulatory period.
- The preliminary decision estimate of 'gamma' over-states the value of imputation credits to investors. Since the 'gamma' factor is used to calculate a deduction from the allowance for corporate tax liabilities to account for the value of imputation credits, over-estimation of gamma will lead to a tax allowance (and therefore a total revenue allowance) that is too low. The shortfall in the allowance for corporate tax liabilities due to over-estimation of gamma is approximately $20m over the 2016 regulatory period.
- The preliminary decision's rejection of our capital allowance for the projects at Flemington, Sunbury and Preston projects. Without these projects JEN's customers in these areas will not receive the supply of electricity to the levels they have asked of us.
- The framework adopted in the preliminary decision to assess JEN's proposed step changes (ie. to only review changes in legal and regulatory obligations as well as demand management payments) is narrow and does not reflect the practicalities of running a distribution business. This, combined with a rejection of some proposed allowances due to insufficient information does not allow JEN to recover its efficient cost.
- The approach taken in the preliminary decision to scaling operating costs for network growth differs to the approach proposed by JEN. JEN accepts the approach adopted in the preliminary decision, however notes that the methods for determining customer number and peak demand growth are inconsistent.

15. We are therefore concerned that if the AER maintains its position in these areas in its final decision, we will face a significant cost recovery shortfall. This will ultimately not be in the long-term interests of consumers, as it is likely to require us to reduce expenditure on programs that are beneficial to customers, including expenditure programs that customers have told us they value. It may also compromise our ability to attract funding for future investment to maintain the network service levels that customers value, and to meet growth in fast growing parts of the area serviced by our network.

OUR SUBMISSION PROMOTES THE OPTIMAL NEO POSITION

16. To develop this submission we reviewed the preliminary decision—including both the overall and the constituent decisions—and analysed material changes that have occurred in the energy market subsequent to our April 2015 proposal. We then went back to our customers and stakeholders to confirm their priorities and preferences for the 2016 regulatory period, and sought expert advice to assist us in forming a view on whether the preliminary decision promotes the Optimal NEO Position. This engagement has helped us develop a submission that responds to the changing energy market in a way that promotes our customers' long-term interests in terms of our service levels, costs, prices and tariff structures.

17. To assist our customers, stakeholders and the AER consider our submission we have developed a 'traffic light' system that clearly and transparently highlights which aspects of the preliminary decision promote the Optimal NEO Position, and based on this assessment, those aspects to which we have:

- Agreed[5] – where the preliminary decision has accepted aspects of our April 2015 proposal as promoting the NER and our customers' long-term interests, or where the preliminary decision has not accepted aspects of our April 2015 proposal but where we have adopted the AER's position for the purposes of our submission ('***green light'***)
- Partially agreed – where we are incorporating aspects of the preliminary decision into our submission whilst maintaining aspects of our April 2015 proposal ('***amber light'***)

[5] These items have been accepted by JEN on the basis that the AER accepts the entirety of JEN's submission. If this is not the case JEN maintains the position on these items that is set out in our April 2015 proposal.

- Disagreed – where we do not agree with the preliminary decision and maintain that our April 2015 proposal or our submission is consistent with the National Electricity Rules (**NER**) and best promotes our customers' long-term interests ('***red light'***).

18. Our submission strikes the right balance between our business and customer outcomes necessary to promote the Optimal NEO Position. Our submission ensures we recover our efficient costs necessary to maintain the safety, reliability and responsiveness of our services over the 2016 regulatory period including adapting our services to our changing energy market.

19. Sections 1-10 of this submission set out how we have considered any material changes that have occurred in the energy market, re-tested our customers' priorities and preferences and sought expert advice to assist us in forming a view on the preliminary decision. It also provides the revenues required and incentive and risk management framework necessary to promote the Optimal NEO Position over the 2016 regulatory period.

20. JEN's views on the AER's preliminary decision are outlined in Figure OV–2.

Figure OV–2: Overview of our response to the preliminary decision

Revenue requirement for our distribution and regulated metering services	ARR, MAR and X-factors	✗
	Regulatory Asset Base (RAB) roll-forward	≈
	Tax Asset Base (TAB) roll-forward	✓
	Depreciation	✓
Rate of return	Tax compensation	✗
	Cost of equity	✗
	Cost of debt and transition	✗
Capex for our distribution services	Replacement capex	✓
	Augmentation capex	≈
	Connections capex (including capital contributions)	≈
	Non-network IT capex	✓
	Non-network other capex	✓

Opex for our distribution services	Base year efficiency	✓
	Opex step changes	✗
	Rate of change	✗
Form of regulation	Service classification	✓
	Control mechanisms	≈
Incentive framework	Efficiency Benefit Sharing Scheme (**EBSS**) and Service target performance incentive scheme (**STPIS**)	✓
	Capex expenditure sharing scheme (**CESS**) and Demand management incentive scheme (**DMIS**)[1]	✗
	F-factor scheme	✓
Risk management framework	Cost pass through framework	≈
Charges for other services	Fee-based services and quoted services (ancillary network services)	≈
	Public lighting[2]	≈
	Negotiating services	✓

[1] Also known as Demand Management and Embedded Generation Connection Incentive Scheme (DMEGCIS)
[2] Covers the operation, maintenance and replacement of public lighting

1. ABOUT THIS SUBMISSION

21. This submission builds on and references material from JEN's regulatory proposal submitted to the AER in April 2015. It incorporates, by reference, all supporting evidence and other material from our April 2015 proposal, and unless otherwise stated, reflects and maintains JEN's position as set out in the April 2015 proposal. Alongside the April 2015 proposal it also provides all the information we are required to submit to comply with the NER[6] as well as supporting information. This submission also incorporates by reference:

- The information provided in April 2015 in response to the Electricity Distribution Price Review (**EDPR**) Regulatory Information Notice (**RIN**) (dated 30 Jan 15)
- Our responses to the questions raised by the AER during its consideration of our April 2015 proposal.

1.1 APPROACH USED TO DEVELOP THIS SUBMISSION

22. To develop this submission, we:

- Considered our April 2015 proposal and analysed material changes that have occurred in the energy market and their implications for our network and our customers over the 2016 regulatory period
- Reviewed the preliminary decision, comprising both the overall decision on the Annual Revenue Requirement (**ARR**) to be recovered from our customers and the constituent decisions, and considered the extent to which the preliminary decision promotes the Optimal NEO Position
- Re-engaged with our customers, stakeholders and the broader community to confirm their priorities and preferences in relation to our service and safety standards, and our prices and tariff structures for the 2016 regulatory period (see Attachment 1-4)
- Reviewed the materials provided by the AER in response to questions raised by JEN following the release of the preliminary decision
- Developed a 'traffic light' system to clearly highlight which aspects of the preliminary decision promote the Optimal NEO Position.

23. We used this information to inform our analysis and decisions for each of the key components of the submission. This ensures that the submission responds to the preliminary decision and any market changes in a way that promotes the Optimal NEO Position. These components include:

- The proposed application of the form of regulation ('the classification of distribution services'), and the proposed incentive and risk management frameworks to apply for the 2016 regulatory period
- The proposed ARR for our distribution services to be recovered from our customers through network prices (or charges), and the annual changes in these prices required to generate this amount of revenue (X-factors)
- The proposed rate of return, and forecast capital expenditure and operating expenditure, which are key inputs to the proposed ARR for our distribution services

[6] NER cl. 6.8.2(a) requires us to submit a regulatory proposal to the AER.

- The proposed ARR for our alternative control metering services to be recovered from our customers through metering prices (or charges), and the proposed rate of return, and forecast capital expenditure and operating expenditure, which are key inputs to the proposed ARR for our metering services
- The proposed fees and charges for ancillary network services.

1.2 HOW TO NAVIGATE THE SUBMISSION

24. The remainder of this submission is structured broadly in line with the approach outlined in section 1.1:

- Chapters 2 to 4 detail each of the main components of the proposed form of regulation, incentive frameworks and risk management framework to apply to our network services for the 2016 regulatory period
- Chapters 5 to 8 detail each of the main components of the submission for our distribution services — including the proposed change in revenue requirements, rate of return, forecast capital expenditure and forecast operating expenditure
- Chapter 9 details each of the main components of the submission for our metering services—including the proposed change in revenue requirements, rate of return, forecast capital expenditure and forecast operating expenditure
- Chapter 10 details the proposed fees and charges for our other network services.

25. We have also provided additional detail via a range of customer-focused summaries and explanations including:

- An accessible 2-page summary that highlights the key elements of our submission and what it will mean for our customers
- An easy-to-read customer overview,[7] which explains our submission, what it will mean for our customers in terms of price and other changes, and how we engaged with customers and stakeholders in developing the proposal
- A range of short targeted 'fact sheets' focusing on specific aspects of the submission to further assist customers in understanding the submission and how it will impact them.[8]

26. Table 1–1 provides a more detailed overview of the structure and content of the submission. It lists the key attachments and supporting information for each chapter.

27. All amounts in this document are in real $2015 unless otherwise specified.

Table 1–1: Structure of the submission

Chapter	Content	Supporting attachments
1. About this submission	• A description of this submission	• 1-1: Claims for Confidentiality • 1-2: Interrelationships, errors and countervailing benefits • 1-3: Continuing engagement with our

7 Ordinarily, NER cl 6.8.2(c1) requires distribution network businesses to submit an overview paper which explains the proposal in plain language to consumers; however for the current EDPR process cl 11.76.2(a) of the NER excuses distribution businesses from developing this. Regardless, in the interests of improving customer engagement JEN has chosen to publish an overview.

8 Available from http://jemena.com.au/home-and-business/price-reviews

Chapter	Content	Supporting attachments
		customers
2. Form of regulation	• Proposed classification of services • Proposed form of regulation to apply to our network services	• 2-1: Classification of services • 2-2: Price control mechanisms
3. Incentive framework	• Proposed incentive schemes to encourage service and cost improvements	• 3-1: Incentive schemes
4. Risk management framework	• Proposed mechanisms to manage risks and uncertainties	• 4-1: Risk management framework
5. Revenue requirement for distribution services	• Overview of proposed annual revenue requirement (ARR or building block costs): – proposed return on and of capital (including opening capital base, forecast capital expenditure, rate of return and regulatory depreciation) – operating and tax costs, and – other proposed revenue adjustments • Proposed maximum allowed revenue and X-factors	• 5-1: Revenue requirement and true up • 5-2: Post tax revenue model (**PTRM**) • 5-3: RAB roll-forward model • 5-4: Asset base roll-forward and depreciation • 5-5: 2010 s-factor close out model
6. Rate of return	• Our proposed rate of return including return on debt and return on equity and how this promotes the long-term interest of our customers • Key areas of agreement and departure from the AER rate of return guidelines • Our proposed implementation of annual updates to the return of debt	• 6-1: Rate of return • 6-2: Rate of return model • 6-3: Averaging periods • 6-4: Frontier Economics - The required return on equity under a foundation model approach • 6-5: Frontier Economics - The relationship between government bond yields and the market risk premium • 6-6: Frontier Economics - Estimating the equity beta for the benchmark efficient entity • 6-7: HoustonKemp - The Cost of Equity: Response to the AER's Draft Decisions for the Victorian Electricity Distributors • 6-8: CEG - Criteria for assessing fair value curves • 6-9: CEG - Critique of the AER's approach to transition • 6-10: CEG - September 2015 cost of debt and inflation forecasts • 6-11: CEG - Critique of AER analysis of New Issue Premium • 6-12: Frontier Economics - The appropriate use of tax statistics when estimating gamma

Chapter	Content	Supporting attachments
7. Forecast capital expenditure for our distribution services	• Our forecast of capital expenditure • How our forecast expenditure meets the NER and promotes the long-term interests of customers	• 7-1: Forecast capital expenditure • 7-2: Capital expenditure model • 7-3: Demand forecast • 7-4: ACIL Allen - Demand forecast report • 7-5: ACIL Allen - Demand forecast models • 7-6: Load demand forecast 2015 • 7-7: Forecast customer numbers • 7-8: ACIL Allen – Forecast customer numbers report • 7-9: ACIL Allen – Forecast customer numbers model • 7-10: Nuttall Consulting - Addendum to April 2015 REPEX report • 7-11: WSPPB - Independent review of Sunbury development strategy • 7-12: Addendum to Sunbury network development strategy • 7-13: WSPPB - Independent review of Flemington development strategy • 7-14: Revised Flemington network development strategy • 7-15: WSPPB - Independent review of Preston development strategy • 7-16: Advisian - Demand management options • 7-17: Power of choice business case • 7-18: Deloitte - Power of Choice business case support • 7-19: Melbourne Airport Development Strategy • 7-20 - Addendum to Preston network development strategy • 7–21 - Updated RIN templates
8. Forecast operating expenditure for our distribution services	• Our forecast of operating expenditure • How our forecast operating expenditure meets the NER and promotes the long-term interests of customers	• 8-1: Operating expenditure forecasting method and base year efficiency • 8-2: Operating expenditure step changes • 8-3: Opex forecasting model • 8-4: IJM Consulting - Audit report of JEN's compliance with Electricity Safety 2010 Regulations • 8-5: Select Solutions - Letter confirming vegetation growth rates • 8-6: Susan Brennan SC - Advice on

Chapter	Content	Supporting attachments
		vegetation management matters • 8-7: Letter from JEN to ESV (23 November 2015) • 8-8: Letter from ESV to JEN (30 November 2015) • 8-9: Letter from ESV to JEN (27 November 2015) • 8-10: KPMG - Definition of RIN actuals • 8-11: Business case for reporting RIN actuals • 8-12: PB – Conversion of RIN information to actuals • 8-13: JEN GSL and Chapter 5A step change model
9. Revenue requirement for metering services	• Overview of proposed annual revenue requirement (ARR or building block costs): – proposed return on and of capital (including opening capital base, forecast capital expenditure, rate of return and regulatory depreciation) – operating and tax costs, and – other proposed revenue adjustments • Proposed maximum allowed revenue and X-factors	• 9-1: Alternative control metering services • 9-2: PTRM - ACS Metering services • 9-3: ACS Metering (capital expenditure) model • 9-4: ACS Metering (operating expenditure) model • 9-5: ACS roll-forward model • 9-6: Metering exit fees model • 9-7: Huegin - Benchmarking Victorian metering expenditure from 2009 to 2014 • 9-8: KPMG - Report on metering base year adjustment
10. Our fees and charges for other services	• How we propose to change fees and charges for ancillary network services, public lighting OM&R services and negotiated services.	• 10-1: Alternative Control Services and other negotiated services • 10-2: ACS public lighting charges model • 10-3: ACS cost build up model • 10-4: ACS ancillary network services charges model • 10-5: Negotiation framework

1.3 CLAIMS FOR CONFIDENTIALITY

28. From time to time the benefit of publishing some confidential information may be outweighed by the potential harm. For example, we may provide an estimate of the cost of providing a service we plan to competitively tender for. If the AER were to publish this information it could undermine our ability to obtain competitive tenders from the market, and ultimately increase the costs to consumers. As a result, we have marked some of the information in this submission as confidential.

29. The AER has sought to balance transparency and confidentiality by outlining, in a guideline[9], what information should be marked as confidential and how this should be done. We have applied the guideline requirements in to this submission as outlined in Attachment 1-1.

1.4 FEEDBACK ON THIS SUBMISSION

30. We recognise that Australia's energy markets are undergoing significant change that has major implications for JEN and our customers. We are committed to engaging with our customers, stakeholders and the broader community to help ensure the business decisions we make respond to these changes in a way that reflects our customers' preferences and promotes their long-term interests.

31. We invite our customers, stakeholders and the broader community to get involved in the AER's review of our submission.

32. Customers can make a submission to the AER at VICelectricity2016@aer.gov.au. Customers can also provide feedback or seek further information from us directly—either by sending an email to haveyoursay@jemena.com.au, or via the 'get involved' section on our website.

33. We encourage our customers and stakeholders to subscribe to receive email updates about our pricing and other customer engagement activities via our website.[10]

9 AER, *Better Regulation: Confidentiality guideline*, 19 November, 2013.

10 http://jemena.com.au/home-and-business/price-reviews/get-involved

2. FORM OF REGULATION

Table 2–1: Overview of our response to the preliminary decision on form of regulation and risk management framework

Components of form of regulation	Our response to the preliminary decision
Service classification	✓
Control mechanisms	≈

Key messages

- The NER recognise that there are varying levels of competition in providing the network services that customers value, and therefore that direct regulation of services, costs and prices may only be required for those services where minimal competition exists.
- Our proposed classification of services in this submission is largely consistent with our April 2015 proposal and the preliminary decision—with minor modifications seeking clarification on the definition of connection services and Type 5 and Type 6 meter services to reflect recent regulatory changes—and is likely to promote the Optimal NEO Position.
- Our proposed control mechanisms are consistent with our April 2015 proposal and the preliminary decision with modifications to the control mechanism formulas and its respective parameters to ensure they promote the Optimal NEO Position for the 2016 regulatory period.

34. The NER require us to propose the form of regulation to apply over the regulatory period, including:

- How each network service we provide is to be regulated ('the classification of distribution services'[11]), and
- For services that are to be directly regulated, the form of price control to apply ('the control mechanisms'[12]), taking account of the AER's position in its framework and approach paper (**F&A**).[13,14]

35. If we are to manage our business in a way that promotes the Optimal NEO Position, each of these elements needs to be responsive and adaptable to changing circumstances—including changes in the way our network is used as new technologies and new market players emerge and develop. For example, classifying our different network services needs to be adaptable to reflect new competitive tensions that may emerge during the 2016 regulatory period.

11 NER cl. 6.8.2(c)(1)(i) and (ii) require us to include a classification proposal in our regulatory proposal.

12 NER cl. 6.8.2(c)(3) requires our regulatory proposal to demonstrate the application of the control mechanism, as set out in the framework and approach paper, and the necessary supporting information, for services classified as alternative control services.

13 NER cl. 6.8.1(a)(2) requires the AER to publish a framework and approach paper to apply for the 2016 regulatory period if it has signalled its intent to make an amended or replacement framework and approach paper. Among other things the framework and approach paper must set out the AER's proposed approach to the classification of services, the formula to give effect to the control mechanisms and the application of the incentive schemes.

14 AER *Final framework and approach for the Victorian Electricity Distributors – Regulatory control period commencing 1 January 2016*, October 2014.

36. This chapter provides an overview of our proposed form of regulation for the 2016 regulatory period. Attachment 2-1 provides further detail on the classification of services and Attachment 2-2 provides further detail on the control mechanisms.

2.1 PROPOSED SERVICE CLASSIFICATION

37. We provide a range of essential services to our customers. Some of these services—such as our core distribution network service—are provided solely by us. However, other services are provided in more competitive markets, meaning we compete alongside other businesses to provide these services to our customers.

38. The NER[15] and the AER[16] recognise that there are varying levels of competition in providing the network services that customers value, and therefore that direct regulation of services, costs and prices may only be required for those services where minimal competition exists. The NER require us to propose how our services should be regulated ('the classification of distribution services'),[17] including which services:

- Require direct regulatory control by the AER of the prices we charge or revenues we recover from our customers, including standard control or alternative regulatory controls[18]
- Require indirect regulatory control, with the AER approving a negotiating framework and/or being involved in any arbitration[19]
- Are best left unregulated, with outcomes determined in the competitive market.

39. Our April 2015 proposal was consistent with the AER's F&A paper for the 2016 regulatory period and was broadly consistent with the classification that applied in the 2011 regulatory period.

40. The preliminary decision retains the proposed service classification in the final F&A paper except for dedicated public lighting services. Instead the preliminary decision classifies these services as alternative control services for the 2016 regulatory period (consistent with the 2011 regulatory period).

41. We welcome the preliminary decision's classification of dedicated public lighting services as an alternative control service for the 2016 regulatory period, and we have incorporated this change into this submission. Our proposed classification of services in this submission (outlined in Figure 2–1) is largely consistent with our April 2015 proposal and the preliminary decision—with minor modifications in order to clarify the definition of connection services and Type 5 and Type 6 meter services to reflect recent regulatory changes—and will promote the Optimal NEO Position. Attachment 2-1 provides further detail on the proposed service classification.

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15 NER cl. 6.2.2(c)(1).

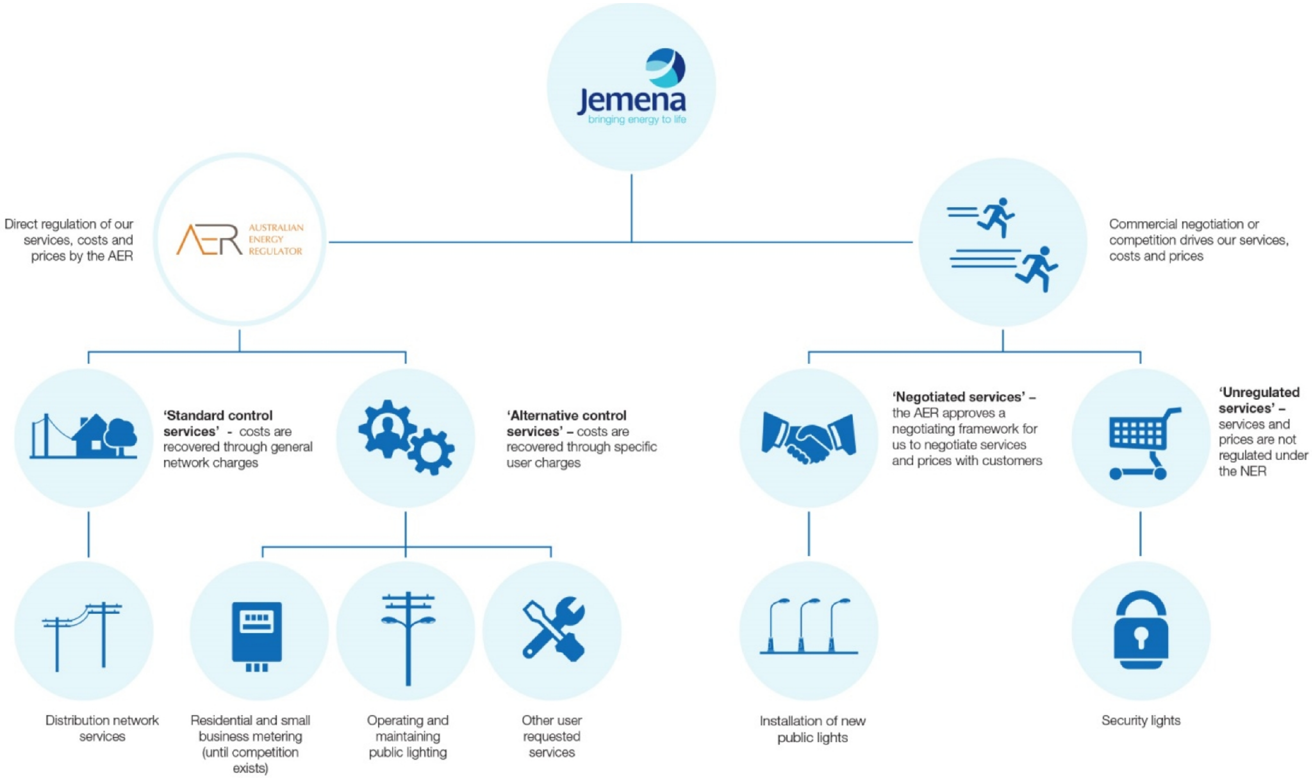
16 The AER's framework and approach paper highlights that "where there is considerable scope to take advantage of market power, our regulation is more prescriptive. Less prescriptive regulation is required where prospect of competition exists. In some situations we may remove regulation altogether." AER, *Final Framework and Approach for the Victorian Electricity Distributors*, 24 October 2014, p 11.

17 NER cl. 6.8.2(c)(1)(i) and (ii) require us to include a classification proposal in our regulatory proposal.

18 The AER notes that they classify standard control services as those distribution services that are central to electricity supply and therefore relied on by most (if not all) customers, with alternative control services being customer specific or customer requested services. AER, *Final Framework and Approach for the Victorian Electricity Distributors*, October 2014, p 15-16.

19 The AER notes that this is appropriate for services where all relevant parties have sufficient countervailing market power to negotiate the provision of those services. AER, *Final Framework and Approach for the Victorian Electricity Distributors,* October 2014, p 18.

Figure 2–1: Proposed classification of our services for the 2016 regulatory period



2.2 CONTROL MECHANISMS TO APPLY TO DIRECT CONTROL SERVICES

42. The NER requires a form of price or revenue control (known as the control mechanism) for those services that are to be directly regulated,[20] and the formulae to give effect to the control mechanism. The control mechanism determines how prices or revenues are adjusted over time.

43. Our April 2015 proposal was consistent with the AER's F&A paper for the 2016 regulatory period and we welcome the preliminary decision's confirmation of this approach, such that our:

- Distribution services will be regulated through a revenue cap, with the basis of control being CPI-X
- Metering services[21] (those not subject to competition) will be regulated through a revenue cap with the basis of control being CPI-X
- Other services (other alternative control services) are to be regulated through a cap on individual prices.[22]

44. The preliminary decision also specifies the control mechanism formulae and their respective parameters. We have considered the preliminary decision's formulas and consider that aspects of the formulas are unlikely to promote the Optimal NEO Position given that, among other reasons:

[20] NER cl. 6.2.5(b).

[21] See chapter 9 for a definition of metering services.

[22] These services can be either a fee based service or a quoted service.

- The application of the formulas is likely to result in the double-counting of adjustments made for the s-factor scheme, and
- The introduction of a side constraint to metering services is inconsistent with the NER.

45. Our submission includes modifications to the control mechanism formulae and the respective parameters to ensure they promote the Optimal NEO Position for the 2016 regulatory period. Further detail is provided in Attachment 2-2.

3. INCENTIVE FRAMEWORK

Table 3–1: Overview of our response to the preliminary decision on the incentive framework

Components of incentive framework	Our response to the preliminary decision
Efficiency Benefit Sharing Scheme	✓
Capital Expenditure Sharing Scheme	✗
Service Target Performance Incentive Scheme	✓
Demand Management and Embedded Generation Connection Incentive Scheme	✗
F-factor scheme	✓

Key messages

- We welcome the preliminary decision's recognition of the importance of the incentive framework, (and our response to these incentives) and in particular the preliminary decision's approach to continuing the strong and balanced incentives for delivering operating cost efficiencies and service standards through the Efficiency Benefit Sharing Scheme (**EBSS**) and Service Target Performance Incentive Scheme (**STPIS**). This approach promotes the Optimal NEO Position.
- However, the preliminary decision's approach to the Capital Expenditure Sharing Scheme (**CESS**) and Demand Management and Embedded Generation Connection Incentive Scheme (**DMEGCIS**)[23], does not promote the Optimal NEO Position as:
  - The approach impacts the ability of JEN to recover at least its efficient costs and has the potential to impact efficient investment in our distribution system, efficient provision of electricity network services and the efficient use of the distribution system (which is not consistent with the aims of section 7A of the National Electricity Law (**NEL**))
  - The approach to the CESS weakens the incentive to deliver service performance improvements consistent with their value to customers, and is inconsistent with the objectives and the AER's approach to the STPIS
  - The approach to the DMEGCIS weakens the incentive to invest in demand management, which is inconsistent with our customers' preference for an increase in the DMIS allowance to encourage efficient investment in demand management initiatives.
- JEN accepts the approach to setting the targets in the F-factor scheme.
- Our submission maintains elements of our April 2015 proposal, including the exclusions of reliability improvement capital expenditure from the CESS and the DMEGCIS allowance as it will:
  - Deliver and drive efficient investment in, and operation of, our electricity system
  - Ensure the integrity of the STPIS

[23] Formerly known as the Demand Management Incentive Scheme (**DMIS**).

  - Support investment in demand management to deliver benefits to customers over the longer term, in line with our customers' preference.

- Our submission confirms the link between the incentive schemes and the approved levels of capital and operating expenditures and notes that the capital and operating expenditures must be set at a level that allows us to recover our efficient costs in order for the incentive schemes to operate as intended.

46. The incentive framework set out in the NER provides for a number of specific incentive schemes to encourage continued improvements in the services we provide, including improving our cost efficiency, service standards and managing network demand. These include the EBSS, the CESS, the service target performance incentive scheme, the demand management and embedded generation connection incentive scheme, and the small-scale incentive scheme.

47. The NER[24] require us to indicate how these incentive schemes should apply to our services for the 2016 regulatory period, taking account of how the AER intends to apply these schemes as set out in its F&A paper.

48. This chapter provides an overview of the proposed incentive framework. Further detail is provided in Attachment 3-1.

3.1 EFFICIENCY BENEFIT SHARING SCHEME (EBSS)

49. In most markets, businesses are driven to continually seek to improve their cost efficiency by customer and shareholder expectations or competition. However, it is perceived regulated network businesses can have an uneven incentive to seek such improvements because the five year price reset process creates an artificial break in the incentives they face.[25]

50. The EBSS is designed to overcome this perception by providing a continuous incentive for us to achieve efficiency savings over time, and improve the value for money of our services by sharing these savings with our customers.[26] The AER made amendments to the EBSS as part of its Better Regulation program,[27] including to the types of operating expenditure that may be excluded from the calculations of efficiency gains or losses (excluded costs).

51. We support the application of a revised EBSS for the 2016 regulatory period. In particular we welcome the preliminary decision's exclusion of specific operating expenditure items such as debt raising costs, Demand Management Incentive Allowance (**DMIA**) and Guaranteed Service Level (**GSL**) payments from the EBSS given that forecast operating expenditure for these items are not based on revealed expenditure. In our view, excluding these costs is likely to more appropriately measure our performance against the operating expenditure benchmarks, consistent with the original intent of the EBSS, and promote the Optimal NEO Position.

52. We have incorporated in our submission the specific operating expenditure items that the preliminary decision determined were not to be excluded from the EBSS for the 2016 regulatory period.

53. Further detail is provided in Attachment 3-1.

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24 NER Cl. S6.1.3.

25 If we make savings late in the regulatory period they will be immediately taken out of allowed prices as part of the five year price reset. This dampens our incentives to make efficiency savings, and is unlikely to be in the long-term interest of our customers.

26 The AER notes that operating efficiency gains or losses are shared approximately 30:70 between distributors and consumers. AER, *Final Framework and Approach for the Victorian Electricity Distributors*, October 2014, p 105.

27 AER, *Efficiency Benefit Sharing Scheme*, 29 November 2013.

3.2 CAPITAL EXPENDITURE SHARING SCHEME (CESS)

54. The CESS is designed to reward network businesses when they improve the efficiency of their capital expenditure, and penalise them when the efficiency of this expenditure diminishes. Under the scheme, financial rewards from capital efficiency gains (or financial penalties for capital efficiency losses) over a regulatory period are added to (or subtracted from) the business' annual revenue requirements for the next regulatory period.[28]

55. The CESS is a new incentive scheme, developed in response to Australian Energy Market Commission (**AEMC**) changes to the NER,[29] to enhance the financial incentives for network businesses to improve their capital expenditure efficiency.

56. The AER proposed that the CESS apply for the 2016 regulatory period in its F&A paper and outlined how the scheme would be implemented as part of its Better Regulation program.[30] To calculate the rewards or penalties, the AER may make adjustments to account for any excluded costs.

57. Our April 2015 proposal broadly supported the application of the CESS as outlined by the AER for the 2016 regulatory period, with minor modifications to exclude reliability improvement capital expenditure to ensure our performance against the capital expenditure benchmarks and that other incentive schemes are not distorted.

58. The preliminary decision does not accept the modification we proposed on the grounds that the AER considers that it would distort expenditure towards reliability capital expenditure that is not valued by customers.[31]

59. We have considered the preliminary decision's reasons, including the explanatory statement for the CESS guideline.[32] However, the preliminary decision's application of the CESS for the 2016 regulatory period (without JEN's minor modifications) does not promote the Optimal NEO Position given it would weaken the incentive to deliver service performance improvements consistent with its value to customers, has the potential to weaken our ability to achieve efficient investment in our electricity system and is inconsistent with the NER[33] and the AER's approach to the STPIS.

60. Our submission therefore includes minor modifications (which exclude reliability improvement capital expenditure from the CESS for the 2016 regulatory period) to be consistent with our April 2015 proposal.

61. Further detail is provided in Attachment 3-1.

3.3 SERVICE TARGET PERFORMANCE INCENTIVE SCHEME (STPIS)

62. The STPIS[34] is designed to create a financial incentive for network businesses to maintain and improve their service performance. It is intended to work alongside the EBSS and CESS to ensure that cost efficiencies

[28] These rewards or penalties are added or subtracted as a separate building block in calculating the annual revenue requirements, as outlined in chapter 5.

[29] The AEMC made changes to the NER to improve the 'ex-ante' and 'ex-post' incentives for network businesses to improve their capital expenditure efficiency. The ex-ante measures included the CESS and the ability of the AER to use depreciation based on actual or forecast capital expenditure to update the regulatory asset base at the end of a regulatory period. The ex-post measures included the ability of the AER to exclude inefficient capital expenditure over-spends from the RAB.

[30] AER, *Better Regulation, Capital expenditure incentive guideline for electricity network service providers*, November 2013.

[31] AER, *Preliminary decision, Jemena distribution determination 2016 to 2020, Attachment 10 – Capital expenditure sharing scheme*, October 2015, p 10-7.

[32] AER, *Explanatory Statement, Capital Expenditure Incentive Guideline for Electricity Network Service Providers, November 2013*, pp. 39-40.

[33] NER, Cl. 6.6.2(b)(3)(iv).

[34] AER, *Electricity distribution network service providers—Service target performance incentive scheme*, November 2009.

rewarded under these schemes do not arise as a result of network businesses lowering service quality for customers. Like these other schemes, financial rewards (or penalties) over a regulatory period are added to (or subtracted from) the business' annual revenue requirements for the next regulatory period.[35]

63. The STPIS contains two measures that create incentives for improved service performance. The s-factor component has applied to our business for the 2011 regulatory period, while the GSL component has not applied because there is a Victoria-specific GSL scheme in place.[36]

64. Our April 2015 proposal was to continue to apply the s-factor component of the STPIS, and that its application be consistent with that set out in the F&A paper.

65. We welcome the preliminary decision's support of our April 2015 proposal.

66. Our submission is consistent with our April 2015 proposal but notes the need to amend the CESS to ensure it does not conflict with the STPIS. Further detail is provided in Attachment 3-1.

3.4 DEMAND MANAGEMENT AND EMBEDDED GENERATION CONNECTION INCENTIVE SCHEME (DMEGCIS)

67. The DMEGCIS is designed to provide electricity distribution businesses with financial incentives to improve network utilisation, specifically by considering alternatives to building peak network capacity ('demand management').[37] The DMEGCIS consists of two parts, both of which have applied to our business over the 2011 regulatory period, being Part A—which provides for an innovation allowance to be incorporated into a distribution network business' annual revenue requirement—and Part B—which compensates a network business for any foregone revenue demonstrated to have resulted from demand management initiatives approved under Part A.

68. Our April 2015 proposal was for only Part A of the DMEGCIS to continue to apply in the 2016 regulatory period consistent with the position in the F&A paper, and for the allowance for demand management projects to be increased to $5.6m over the 2016 regulatory period to provide greater scope for investment in demand management projects, and where efficient, to resolve network supply quality and capacity constraints using demand management.

69. We welcome the preliminary decision's recognition of the benefits from continuing with Part A of the DMEGCIS for the 2016 regulatory period. However, it also limits the allowance to $0.2m per year. As such, it will significantly weaken the incentive for us to invest in demand management – including our direct load trial and the distributed grid energy storage trial that we had proposed for the 2016 regulatory period. Creating unnecessary barriers to efficient investment in demand management initiatives is inconsistent with our customers' preference for investment in demand management initiatives and an increase in the DMIA.[38] For these reasons this aspect of the preliminary decision does not promote the Optimal NEO Position.

[35] These rewards or penalties are added or subtracted as a separate building block in calculating the annual revenue requirements, as outlined in chapter 5.

[36] In Victoria, the Electricity Distribution Code and Public Lighting Code set out GSLs that apply to the Victorian distributors. Essential Services Commission of Victoria, *Electricity Distribution Code, Version 7*, May 2012, p 19; Essential Services Commission of Victoria, *Public Lighting Code*, April 2005, p. 3.

[37] The AER notes that demand management refers to any effort by a distributor to lower or shift the demand for standard control services, including, agreements between distributors and consumers to switch off loads at certain times and the connection of small-scale 'embedded' generation reducing the demand for power drawn from the distribution network. AER, *Final Framework and Approach for the Victorian Electricity Distributors*, October 2014, p 113.

[38] See Attachment 1-3 to this submission.

70. Our submission includes an increase in the DMEGCIS allowance to $5.6m for the 2016 regulatory period consistent with our April 2015 proposal. Further detail is provided in Attachment 3-1.

3.5 F-FACTOR SCHEME

71. The Victorian Government's 'f-factor scheme' provides financial incentives for network businesses to reduce the risk of fire starts and the associated loss or damage.

72. Under the *f-factor scheme order 2011*[39] issued under the National Electricity (Victoria) Act 2005 (Vic) the AER must make various decisions, including setting a fire start target for each network business based on the average historical fire starts over the five previous calendar years. The AER can also set the incentive rate to reward (or penalise) each business for performing better (or worse) than its target.

73. Our April 2015 proposal was to adopt the scheme as outlined in the F&A paper including the incentive rates determined for the 2011 regulatory period. However, we proposed that the target increase to 72.3 from 56.8 established in the 2011 regulatory period to reflect an average over the 2012-2014 period.

74. The preliminary decision did not to approve our proposed f-factor scheme on the grounds that it is not consistent with the F&A with the preliminary decision applying a target of 66.1 per year based on a five year average.

75. Following a response to JEN's questions[40] on how the AER established the target and analysing the method, JEN accepts the approach adopted by the AER to set the target at 66.1.

76. Other than the variation in the f-factor target noted above our submission is consistent with our April 2015 proposal. Further detail is provided in Attachment 3-1.

[39] Victoria Government Gazette, No. G 25 Thursday 23 June 2011.

[40] Email from Moston Neck, Director, AER, 20 November 2015.

4. RISK MANAGEMENT FRAMEWORK

Table 4–1: Overview of our response to the preliminary decision on the risk management framework

Component of risk management frameworks	Our response to the preliminary decision
Cost pass through framework	≈

Key messages

- We accept much of the preliminary decision relating to the nominated pass through events in our April 2015 proposal.
- However, we consider that the definitions of insurer credit risk event, natural disaster event and terrorism event in our April 2015 proposal should be utilised because–in contrast to the proposed definitions in the preliminary decision–they best promote the Optimal NEO Position given they are:
    - Clear, certain and transparent
    - Effectively capture, and appropriately balance, the consequences of the risk event
    - Ensure the focus is on the appropriate NEO considerations (in particular the cost impact of the event rather than other measures of magnitude)
    - Are consistent with the nominated pass through considerations in the NER.
- For this reason we maintain JEN's proposed definitions for insurer credit risk event, natural disaster event and terrorism event as set out in our April 2015 proposal.

77. Under the NER there are a number of ways in which distribution businesses like JEN can manage unforeseen, uncontrollable and material changes in cost. Taken together, these make up our risk management framework.

78. The risk management framework includes the ability for us to nominate pass through events[41] to apply over the 2016 regulatory period to allow the AER to adjust our network prices up or down in response to changes in costs attributable to those specific types of events. If we are to manage our business in a way that promotes the Optimal NEO Position, our determination needs to incorporate an appropriate set of nominated pass through events that can apply in addition to those events stipulated in the NER.

79. This chapter provides an overview of our proposed risk management framework for the 2016 regulatory period. It then outlines each proposed element in more detail.

4.1 OVERVIEW OF PROPOSED RISK MANAGEMENT FRAMEWORK

80. The risk management framework comprises multiple components:

- Insurance, including self-insurance
- Contingent projects

[41] NER cl 6.6.1(a1).

- Cost pass through.

81. One means for us to manage increases in costs attributable to certain unanticipated events is by maintaining appropriate insurance policies. Our operating expenditure allowance already reflects an amount for insurance premiums. This is because our past payments of insurance premiums formed part of our base year operating expenditure, which was accepted in the preliminary decision. Accordingly, JEN does not seek any changes to the insurance element of the risk management framework applicable to us.

82. Another mechanism for us to manage increases in costs is by triggering 'contingent projects'. The value of a contingent project must be at least of $30m or 5% of JEN's annual revenue requirement for 2016, whichever is higher. In order to propose a contingent project, we need to specify appropriate specific and objective trigger events following which the project becomes necessary. JEN has not identified any projects that meet this criterion in the 2016 regulatory period.

83. The third component of JEN's risk management framework is the application of appropriate cost pass through events for the 2016 regulatory period. This forms the focus of our proposed changes to the risk management framework in this submission.

4.2 PASS THROUGH EVENTS

84. The NER[42] sets out a number of pass-through events that, when triggered, allow for the adjustment of our distribution services revenues up or down in response to the costs associated with these events. These are:

- A regulatory change event
- A service standard event
- A tax change event
- A retailer insolvency event
- Any other event specified in a distribution determination as a pass-through event for the determination period.

85. The last of these categories allows distribution businesses to nominate specific pass through events for AER approval.

86. In our April 2015 proposal, we nominated the following pass through events:

1. Insurance cap event — where the cost of an insurable event is greater than the benefit to be paid under the insurance policy
2. Insurance credit risk event — where an insurer becomes insolvent and JEN incurs higher or lower costs in the form of higher premiums, higher or lower deductibles or claim limits, or JEN must absorb the cost of claims which would have been covered under the insurance policy issued by the insolvent insurer
3. Natural disaster event — any fire, flood, earthquake, or other natural disaster which increases the cost of providing direct control services
4. Terrorism event — any act which occurs for political, religious, ideological, ethical or similar purposes which increases the costs of providing direct control services

42 NER cl. 6.5.10.

5. Retailer insolvency event — the failure of a retailer to pay JEN to provide direct control services
6. End of metering derogation event — costs incurred as a result of the expiry of the Victorian Metering Derogation and the introduction of metering contestability
7. Carbon cost event — the imposition of obligations under any carbon scheme.

87. The preliminary decision approved, with modifications, the first five events listed above and did not approve the end of metering derogation event and carbon cost event. The preliminary decision also approved the application of the pass through events to alternative control services.

88. We accept the preliminary decision in respect of a number of these nominated events. However, we disagree with the preliminary decision positions relating to our proposed definitions for:

- Insurer credit risk event
- Natural disaster event
- Terrorism event.

89. For these three events, we consider that our April 2015 proposal definitions are more appropriate for meeting the Optimal NEO Position than the definitions in the preliminary decision. This is because our definitions:

- Are clearer, more certain and more transparent than the AER’s definitions
- Effectively capture and appropriately balance the consequences of the relevant event
- Ensure the focus is on the cost implications of the event rather other measures of magnitude, consistent with the focus of the NEO.

90. Attachment 4-1 provides further detail.

5. REVENUE REQUIREMENT FOR DISTRIBUTION SERVICES

Table 5–1: Overview of our response to the preliminary decision on revenue requirements for our distribution services

Components of revenue requirement for distribution services	Our response to the preliminary decision
Annual revenue requirement ('building block costs')	✖
Maximal Allowed Revenue ('smoothed' revenue) and X-factors	✖
Regulatory Asset Base (RAB) roll-forward	≈
Tax Asset Base roll-forward	✔
Return of assets (Depreciation)	✔

Key messages

- In developing our proposed revenues and X-factors, our submission complies with all relevant NER requirements, including using a 'building block' approach and the AER's post-tax revenue model. In doing so, we have also taken into account the changes occurring in our energy market and our customers' priorities and preferences.
- Our submission total revenue requirement for the 2016 regulatory period is $1,430m. This amount reflects the efficient costs of providing our distribution services and meeting the safety and service levels our customers expect and value, while prudently balancing cost and price pressures in future regulatory periods.
- Our April 2015 proposal 'smoothed' revenue requirement (or maximum allowed revenues (**MAR**)) and X-factors reflected our customers' feedback. However, the preliminary decision will cause volatility in JEN's revenue path.
- Our submission promotes the Optimal NEO Position:
  - The ARR provides sufficient revenue over the 2016 regulatory period to allow us to invest in, operate and maintain our network efficiently and earn a reasonable return on our investment in providing the distribution services our customers value over this period
  - The MAR and X-factors minimise price volatility inconsistent with our customers' preference to offset the introduction of a new 'demand' charge in 2018
- Minor modifications are required to the RAB roll-forward method to ensure it appropriately captures the impact of inflation.

91. The NER require that we propose the 'X-factors' that determine the average change in our network revenue for distribution services in each year of the 2016 regulatory period. The X-factors should reflect the average annual changes in our revenue (on top of changes in CPI) necessary for us to invest in, operate and maintain our network efficiently, and earn a reasonable return on our investment over the regulatory period.

92. The NER require us to determine the X-factors by:

- Calculating our ARR for each year of the regulatory period using a building block approach (See Box 6–1 in our April 2015 proposal for further details),[43] including our proposed:
  - Return on and of capital (including opening capital base, forecast capital expenditure, rate of return and regulatory depreciation)
  - Operating and tax costs, and
  - Other revenue adjustments, including any rewards or penalties from the incentive schemes outlined in chapter 3.
- Calculating the X-factors for each year of the 2016 regulatory period to recover the MAR.

93. This chapter provides an overview of our ARR, MAR and X-factors for distribution services. Further detail is provided in Attachments 5-1 to 5-5.

5.1 OVERVIEW OF PROPOSED ARR, MAR AND X-FACTORS FOR DISTRIBUTION SERVICES

Table 5–2: Overview of proposed ARR, MAR and X-factors for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total	NPV
April 2015 proposal							
Annual Revenue Requirement (‘building block’ costs)	249.27	250.77	271.02	264.31	272.32	**1,307.70**	**1,144.38**
Maximum Allowed Revenue (‘smoothed’ revenue)	256.94	259.68	258.84	263.14	267.51	**1,306.12**	**1,144.38**
X-factors (%)[1]	**(0.29%)**	**(1.06%)**	**0.32%**	**(1.66%)**	**(1.66%)**	**n/a**	**n/a**
Preliminary decision							
Annual Revenue Requirement (‘building block’ costs)	220.94	199.08	216.99	222.62	222.70	**1,082.34**	**978.49**
Maximum Allowed Revenue (‘smoothed’ revenue)	232.68	212.95	210.11	211.46	212.82	**1,080.03**	**978.49**
X-factors (%)[1]	**9.18%**	**8.48%**	**1.34%**	**(0.64%)**	**(0.64%)**	**n/a**	**n/a**
This submission							
Annual Revenue Requirement (‘building block’ costs)	289.05	264.83	292.29	292.90	290.77	**1,429.85**	**1,199.23**
Maximum Allowed Revenue (‘smoothed’ revenue)	233.39	296.43	296.50	302.49	308.55	**1,437.36**	**1,199.23**
X-factors (%)[1]	**9.18%**	**(27.01%)**	**(0.02%)**	**(2.02%)**	**(2.00%)**	**n/a**	**n/a**

(1) Positive amount represents a revenue decrease in real terms.

43 NER cl. 6.4.3 requires the ARR for each regulatory year to be determined using a building block approach.

94. Our proposed ARR for distribution services for the 2016 regulatory period is $227.0m higher than the ARR allowed for by the AER for the 2011 regulatory period. This:

- Reflects increases in capital expenditure (see Chapter 7), operating expenditure (see Chapter 8) and a reward under the EBSS (see chapter 3.1)
- Is partially offset by reductions in funding costs (see chapter 6).

95. Our proposed MAR for distribution services for the 2016 regulatory period is slightly higher than the ARR for the same period in total (yet the same in present value terms) because some revenue is recovered later in the period.

5.2 PROPOSED ANNUAL REVENUE REQUIREMENT

96. The ARR represents the amount of revenue we need over the 2016 regulatory period to allow us to invest in, operate and maintain our network efficiently and earn a reasonable return on our investment in providing the distribution services our customers' value over this period.

97. To calculate our proposed ARR, we used a building block approach (See Box 6–1 in our April 2015 proposal for more details). This involved calculating and summing the following building block costs:

- Return on capital (or funding costs)
- Return of capital (depreciation)
- Forecast operating expenditure
- Forecast tax costs
- Other revenue adjustments.

98. Table 5–3 sets out our revised proposed ARR and building block costs for distribution services over the 2016 regulatory period, and compares these to our April 2015 proposal and the preliminary decision. Each of these inputs underlying the proposed ARR is set out in detail in Attachment 5-1.

Table 5–3: Overview of proposed ARR, MAR and X-factors for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
April 2015 proposal						
Return on capital	83.44	88.03	93.70	98.72	103.69	**467.57**
Return of capital	43.07	49.63	48.40	39.24	45.36	**225.70**
Forecast operating expenditure	95.37	95.36	98.51	103.18	106.60	**499.01**
Tax costs	18.63	18.10	20.23	16.26	17.01	**90.23**
Other revenue adjustments[1]	8.76	(0.34)	10.19	6.91	(0.33)	**25.19**
Total annual revenue requirement	**249.27**	**250.77**	**271.02**	**264.31**	**272.32**	**1,307.70**
Preliminary decision						
Return on capital	69.67	72.72	77.10	80.82	84.60	**384.92**
Return of capital	51.73	39.32	39.90	43.01	46.77	**220.74**

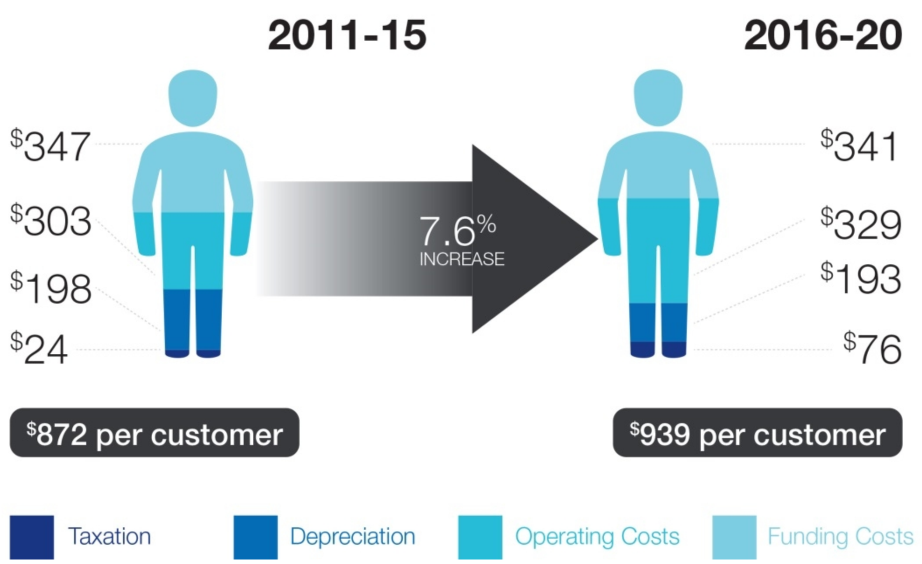
	2016	2017	2018	2019	2020	Total
Forecast operating expenditure	76.42	76.70	77.68	79.00	80.26	**390.07**
Tax costs	14.42	10.62	11.16	11.17	11.19	**58.56**
Other revenue adjustments[2]	8.70	(0.28)	11.14	8.63	(0.13)	**28.05**
Total annual revenue requirement	**220.94**	**199.08**	**216.99**	**222.62**	**222.70**	**1,082.34**
This submission						
Return on capital	101.06	105.04	111.97	113.38	114.33	**545.78**
Return of capital	57.74	45.17	52.83	52.35	56.43	**264.52**
Forecast operating expenditure	93.81	91.83	93.28	95.59	96.38	**470.89**
Tax costs	27.44	22.61	23.50	23.45	23.78	**120.76**
Other revenue adjustments [2]	9.00	0.17	10.72	8.13	(0.13)	**27.89**
Total annual revenue requirement	**289.05**	**264.83**	**292.29**	**292.90**	**290.77**	**1,429.85**

(1) These adjustments relate to (1) rewards under the EBSS for our performance in the 2011 regulatory period, (2) trueing–up actual s-factor performance in 2010 and (3) use of assets that are to be shared in providing both regulated and unregulated services in the 2016 regulatory period. One of the shared assets principles is that a shared asset cost reduction should be applied where the use of the assets other than for distribution services (or SCS) is material.

(2) The preliminary decision and this submission includes a DMIA allowance as per NER clauses 6.4.3(a)(5) and 6.6.3, rather than an operating expenditure allowance (included in our April 2015 submission).

99. Figure 5–1 compares the proposed building block costs for the 2016 regulatory period with those approved by the AER for the 2011 regulatory period on a cost per customer basis.

Figure 5–1: ARR for distribution services per customer – proposed for 2016 regulatory period compared with approved for 2011 regulatory period ($2015)[44,45]



100. Table 5–3 highlights that there is a material difference between what we consider to be the efficient costs of running our network, and what the preliminary decision provided for. It also highlights that we now consider that

44 Other revenue adjustments are captured in the operating expenditure category.

45 These 'per customer costs' were derived by dividing the building block costs by actual and forecast customer numbers.

these costs are higher than in our April 2015 proposal. Specifically, our proposed ARR is $122 million higher than our April 2015 proposal reflecting a higher rate of return, partially offset by lower forecast operating expenditure.

101. Our proposed ARR is $348 million higher than the preliminary decision reflecting:

- Higher return on capital allowance that reflects higher rate of return (see section 6 and Attachment 6-1) and higher capital expenditure (see section 7)
- Higher return of capital that reflects a higher opening RAB and lower forecast inflation (see Attachments 5-4 and 6-1)
- Higher operating expenditure reflecting step changes to capture changes in the external environment (see section 8).

102. Our proposed ARR promotes the Optimal NEO Position given it provides sufficient revenue over the 2016 regulatory period to allow us to invest in, operate and maintain our network efficiently and earn a reasonable return on our investment in providing the distribution services our customers value over the 2016 regulatory period. Conversely, the preliminary decision provides insufficient revenue over the 2016 regulatory period to do these things.

5.3 PROPOSED MAXIMUM ALLOWED REVENUE FOR DISTRIBUTION SERVICES

103. The MAR in the preliminary decision does not promote the Optimal NEO Position if it:

- Does not enable us to maintain our network efficiently and earn a reasonable return on our investment in providing the distribution services our customers value over this period
- Ignores JEN's customer preferences to focus price decreases in 2018 when a new demand charge is being introduced.

104. Our submitted MAR is outlined in Table 5–4.

Table 5–4: Proposed MAR for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total	NPV
April 2015 proposal							
ARR (building block costs)	249.27	250.77	271.02	264.31	272.32	**1,307.70**	**1,144.38**
MAR ('smoothed' revenue)	256.94	259.68	258.84	263.14	267.51	**1,306.12**	**1,144.38**
Preliminary decision							
ARR (building block costs)	220.94	199.08	216.99	222.62	222.70	**1,082.34**	**978.49**
MAR ('smoothed' revenue)	232.68	212.95	210.11	211.46	212.82	**1,080.03**	**978.49**
This submission							
ARR (building block costs)	289.05	264.83	292.29	292.90	290.77	**1,429.85**	**1,199.23**
MAR ('smoothed' revenue)	233.39	296.43	296.50	302.49	308.55	**1,437.36**	**1,199.23**

(1) The Net Present Value (**NPV**) is calculated by discounting the ARR and MAR cash flows, using the nominal vanilla weighted average cost of capital (**WACC**).

105. We 'smoothed' our proposed ARR to derive our proposed MAR for each year of the 2016 regulatory period using an approach consistent with NER requirements[46] and the AER's PTRM. We ensured the MAR is equal to the ARR in net present value terms.

106. Our proposed MAR for our distribution services (Table 5–4) reflects our customers' preference for us to profile the revenue path over the 2016 regulatory period in a way that introduces our proposed changes to our network tariff structure as soon as practical. It also minimises the impact of these changes on specific groups of customers (as a result of a decrease in the MAR in 2018)[47] and provides an opportunity for customers to change their behaviour to minimise their bills (see our proposed Tariff Structure Statement[48]).

107. Whilst our April 2015 proposal sought to minimise the potential for price shocks over the 2016 regulatory period by maintaining a relatively stable revenue path, this is no longer possible with the AER making a preliminary decision that shifts large price reductions into 2016 that will cause our submission revenue path to become more volatile (see section 5.4).

108. Our submission promotes the Optimal NEO Positon as it:

- Provides sufficient revenue over the 2016 regulatory period to allow us to invest in, operate and maintain our network efficiently and earn a reasonable return on our investment in providing the distribution services our customers value over this period
- Minimises the price volatility that is inconsistent with our customers' preference to offset the introduction of a new demand charge in 2018.

109. In setting our proposed prices, we have tried to minimise any adverse impacts of our proposed tariff structure changes on customers. Our proposal is to reduce the levels of our existing charges for residential and small business customers (such as the fixed standing and usage charges) to offset the introduction of a new charge in 2018.

110. We calculated the MAR consistent with the NER[49] and the AER's PTRM (our model is provided as Attachment 5–2).

5.4 PROPOSED X-FACTORS FOR DISTRIBUTION SERVICES

111. Our distribution services will be regulated through a revenue cap in the 2016 regulatory period, with a CPI-X form of price control. The X-factors for the 2016 regulatory period need to reflect the reduction[50] in our revenue (on top of CPI) necessary to allow us to recover our MAR in each year of the period.

112. Our proposed X-factors are shown in Table 5–5. We calculated these X-factors consistent with the NER,[51] the AER's PTRM (our model is provided as Attachment 5–2), and our customer preferences.

46 NER cl 6.5.9.

47 A decrease in the MAR in 2018 for our distribution services will allow us to decrease the fixed and consumption charges to offset the introduction of a new maximum demand charge for residential and small business customers.

48 JEN, *Tariff Structure Statement*, 25 September 2015.

49 NER cl 6.5.9.

50 Note, a positive X factor means a real revenue reduction.

51 NER cl 6.5.9.

Table 5–5: Proposed revenue path X-factors for distribution services (%)

	2016	2017	2018	2019	2020
April 2015 proposal	(0.29%)	(1.06%)	0.32%	(1.66%)	(1.66%)
Preliminary decision	9.18%	8.48%	1.34%	(0.64%)	(0.64%)
This submission	9.18%	(27.01%)	(0.02%)	(2.02%)	(2.00%)

113. Our proposed X-factors reflect the higher ARR and MAR we are proposing relative to the preliminary decision. Contrary to the approach in the preliminary decision, we have sought a price path that will allow us to deliver on our customers' stated preference for maximising our ability to mitigate any bill shock in 2018 associated with introducing demand tariffs for our residential and small business customers.

114. Note that the proposed X-factors do not necessarily determine the actual movements in our individual network tariffs or the actual customer bill outcomes. This is because:

- The X-factors are under a revenue cap and therefore relate to the annual change in revenues. Prices necessary to recover the allowed revenues will depend on the demand forecast in each year
- Under the form of control determined by the AER in its F&A paper, the X-factors will be updated annually to account for unforeseen changes in energy consumption,[52] any costs or savings that the AER approves to be passed through to customers, and annual movements in the return on debt.

115. Actual movements in customers' bills will also depend on their specific circumstances, including which of our network tariffs they are on and the amount of electricity they consume (including how they respond to our proposed changes in tariff structures).

116. We note that our submission X-factor for distribution services in 2018 provides for a reduction in our revenue that is intended to coincide and assist with the transition to the proposed changes to our tariff structures for residential and small business customers (see our TSS for further details on the introduction of our new tariffs). This reflects a key preference to manage customer impacts of tariff reform.[53]

117. The price control mechanism for updating the X-factors is provided as Attachment 2–2. Our proposed network tariffs are outlined in our Tariff Structures Statement and the potential customer bill outcomes are shown in Figure OV–1.

52 The proposed X-factors have been determined based on our forecasts of demand for our distribution and metering services for each year of the 2016 regulatory period. Under a revenue cap the X-factors will be adjusted annually if actual energy consumption is over or under our forecast, to ensure we recover the approved ARR over the 2016 regulatory period (see Attachment 2-2).

53 NER cl. 6.18.5(h).

6. RATE OF RETURN

Table 6–1: Overview of our response to the preliminary decision on the rate of return

Components of rate of return	Our response to preliminary decision
Cost of equity	✖
Gamma	✖
Cost of debt and transition	✖
Forecast inflation	✖

Key messages

- We need to be able to earn a fair rate of return on capital to continue investing in our network in a manner that best promotes the Optimal NEO Position. This rate of return must also comply with the allowed rate of return objective.[54]
- Our April 2015 proposal included a rate of return of 7.18% in the first year of the 2016 regulatory period—which is significantly lower than our allowed rate of return for the 2011 regulatory period (10.33% per annum). This reflects the easing in market conditions after heightened perceptions of risk during the global financial crisis.
- We also proposed that our rate of return be updated in each of the remaining years to account for movements in the return on debt and ensure the benefits of further reductions in interest rates are passed on to our customers.
- The preliminary decision does not provide for an overall rate of return that is consistent with the allowed rate of return objective and does not promote the Optimal NEO Position as:
  - The allowed rate of return is not commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to JEN in respect of our distribution services
  - The value of imputation credits is over-estimated, meaning that the reduction to the overall return to account for imputation credits is too large
  - The AER's forecast of inflation does not reflect current market expectations, which means that the preliminary decision over-estimates the return that investors will get from indexing the RAB.
- Our submission includes a rate of return of 8.62% in the first year of the 2016 regulatory period—which is higher than our April 2015 proposal because of an upward shift in the risk free rate. Our submission also includes forecast inflation of 2.19% per year, which is lower than our April 2015 proposal because it is estimated using a method that better reflects current market conditions.
- Our proposed rate of return in this submission reflects the efficient costs associated with borrowing in debt markets and providing returns to investors in equity markets, and reflects the risks associated with providing distribution services to our customers over the 2016 regulatory period—and therefore promotes the Optimal NEO Position.
- We note that the Australian Competition Tribunal (the **Tribunal**) is currently considering the merits of rate of return, gamma and inflation proposals that are similar to ours. Our submission is made without knowing the Tribunal's

54 NER, cl. 6.5.2(b).

position on these proposals, and so we may need to reconsider these once this position becomes known.

118. The rate of return is a key input used to calculate the return on capital allowance—the largest 'building block cost' in our proposed annual revenue requirement (see chapter 5). The rate of return represents the costs of funding investment in our network through borrowings from debt markets and investments from equity holders. Both of these funding costs are influenced by financial market conditions—and like all businesses, we must pay the going rate for debt and equity capital.

119. The NER require us to propose a benchmark rate of return that (among other things) reflects the funding costs for a benchmark efficient entity with a similar degree of risk as that which applies to JEN in providing distribution services to our customers over the 2016 regulatory period.[55] Using a benchmark rate of return (rather than JEN's actual funding costs) means we have an incentive to 'beat the benchmark' by continually improving the efficiency of our funding costs, much like we have for other costs such as capital expenditure and operating expenditure.

120. In developing our proposed rate of return, gamma and forecast inflation in this submission, we were guided by the requirements in the NER and the AER's Rate of Return Guideline.[56] We considered the preliminary decision, and other recent decisions, and also analysed financial market conditions for debt and equity capital over the 2016 regulatory period, and the changes occurring in our energy market in this period and beyond.

121. We also note that the Tribunal is considering whether rate of return, gamma and forecast inflation proposals made by other networks satisfy the NER requirements. We developed our proposed rate of return, gamma and forecast inflation without the benefit of the Tribunal's decisions on these proposals. We may reconsider our proposal once these decisions are available.

122. This chapter provides an overview of our submission rate of return including the approach we used to calculate this rate of return and forecast inflation, and sets out our concerns that the approach set out in the preliminary decision does not promote the Optimal NEO Position. Attachment 6-1 provides further detail on our approach we used to calculate the rate of return, the value of imputation credits (gamma) and the method for forecasting inflation.

6.1 OVERVIEW OF PROPOSED RATE OF RETURN

123. Our submission rate of return for distribution services over the 2016 regulatory period (shown in Table 6–2) is lower than our allowed rate of return for the 2011 regulatory period. This reflects the easing in market conditions following the heightened perceptions of risk in global and domestic financial markets during the global financial crisis from 2008 to 2010. Our proposed rate of return, which will be updated annually through the 2016 regulatory period to account for movements in the cost of debt, ensures that the benefits of reduced interest rates and some reduced perceptions of risk are passed on to our customers.[57]

124. Our submission rate of return is higher than the preliminary decision as we have:

- Had regard to a range of equity models as we consider this is a more prudent approach given no one model captures all relevant information or reflects reality perfectly
- Used a lower value for gamma that better reflects how investors value imputation credits

[55] NER cl. 6.5.2 (b) – (l).

[56] AER, *Better regulation, Rate of return guideline*, December 2013.

[57] The proposed rate of return will also be used to determine the building block costs for our alternative control metering services (see chapter 9) and public lighting services (see chapter 10).

- Used a transition to the trailing average return on debt that better reflects efficient financing practices in workably competitive markets—namely an immediate transition to that average.

Table 6–2: Proposed rate of return (‘nominal vanilla WACC’) for distribution and metering services (%)

Parameter	April 2015 proposal	Preliminary decision	This submission
Return on equity	9.87%	7.30%	9.89%
Return on debt	5.39%	5.16%	7.77%
Inflation	2.52%	2.50%	2.19%
Leverage	60.00%	60.00%	60.00%
Gamma[1]	25.00%	40.00%	25.00%
Corporate tax rate	30.00%	30.00%	30.00%
Nominal vanilla WACC	**7.18%**	**6.02%**	**8.62%**

(1) Return on debt, return on equity, and nominal WACC estimated using data from the sample averaging period of the 20 business days, further detail on the proposed averaging period is provided in attachment 6-1.

125. This proposed rate of return complies with all requirements in the NER.[58] In particular, it:

- Reflects the efficient financing costs of a benchmark firm with a similar degree of risk (the ‘allowed rate of return objective’)
- Has been calculated using a weighted average of the return on equity and the return on debt
- Is determined on a nominal vanilla basis
- Incorporates an estimate of the value of imputation credits (‘gamma’) consistent with the market’s valuation, and
- Reflects prevailing conditions in the market for equity funds.

126. The proposed rate of return in this submission reflects the efficient costs associated with borrowing in debt markets and providing returns to investors in equity markets—and reflects the risks associated with providing distribution services to our customers over the 2016 regulatory period. Therefore, we consider that using the proposed rate of return to calculate the return on capital allowance of the ARR promotes the Optimal NEO Position.

6.2 PROPOSED RETURN ON EQUITY

127. Our proposed return on equity for the 2016 regulatory period is 9.89% (compared with 11.1% for the 2011 regulatory period).[59] This component accounts for 40% of the proposed rate of return.

58 NER cl. 6.5.2 (b) – (l).

59 This value rounds to 9.9% when input into the AER’s PTRM.

6.2.1 EQUITY MODELS AND ESTIMATION APPROACH WE USED

128. As it is not possible to directly observe the return investors expect for committing their money to a benchmark firm, we have used a range of models and other evidence to estimate a benchmark return on equity. We also considered the risk associated with investments in services such as ours.

129. Consistent with the guidance from the AEMC, we consider it prudent to use a range of models and evidence in estimating the benchmark return on equity. This is consistent with real-world practice in financial markets that recognises that all models are a simplification of the real world and that some approaches provide greater insight than others.[60]

130. We also recognise that there may be other ways to estimate a return on equity that satisfies the rate of return objective. So, we have provided in our submission two estimates of the return on equity:

- One that uses a simple average of estimates from four relevant models—the multi-model approach
- Another that starts with one of those models (the SL-CAPM) and adjusts it for known biases—consistent with the AER's foundation model approach (that was applied in the preliminary decision).

131. Our submission relies on the second of these two estimates, which we consider better reflects the AER foundation model approach as set out in the rate of return guideline and provides an estimate of 9.89%. This compares to the 9.74% estimated using the first approach.

132. Table 6–3 sets out our estimate using the first approach. Table 6–4 does the same for the second approach.

Table 6–3: Estimated return on equity using multi-model approach (%)

Model	April 2015 proposal – Return on equity	April 2015 proposal - Weighting	This submission – Return on equity	This submission - Weighting
SL-CAPM	9.32%	25%	9.20%	25%
Black CAPM	9.93%	25%	9.80%	25%
Fama-French model	9.93%	25%	9.82%	25%
Dividend discount model	10.32%	25%	10.15%	25%
Simple average	**9.87%**	**100%**	**9.74%**	**100%**

133. We consider using a simple average is appropriate given that no one model is perfect or provides all information relevant to estimating the return on equity. As outlined in Box 6-1 and explained in detail in Attachment 6-1, there are material concerns with the accuracy of the SL-CAPM, and if adopted without adjustment (as in the preliminary decision), this would materially understate the return on equity required by investors in a benchmark entity. A simple average of the above four models helps overcome (or minimise the impact of) such shortcomings.

134. Alternatively, if one were to use the SL-CAPM to estimate the return on equity as a 'foundation model' (as was done for the preliminary decision), it needs to be properly adjusted for two well-recognised biases in the design of that model, (1) the low beta bias, and (2) the book-to-market bias. Our proposed return on equity (9.89%) does this.

60 AER, *Better regulation, Rate of return guideline – Explanatory Statement*, December 2013, p 64.

Table 6–4: Estimated return on equity using the foundation model approach (%)

Step	Adjustment	Estimate
Unadjusted SL-CAPM (as per Table 6–3)		**9.20%**
Adjust for low beta bias	0.45%	
Adjust for book-to-market bias	0.24%	
Final estimate		**9.89%**

(1) Further detail on the two adjustments is set out in Attachment 6-1, and is sourced from expert advice from Frontier.

135. In estimating our proposed return on equity, we have sought to use an approach that:

- Is transparent and relatively simple to apply
- Uses a range of publicly available information
- Is likely to provide sustainable, stable and robust ‘consensus’ forecasts that provide stability in funding costs and reduce unnecessary volatility in our network prices
- Ensures that there is no bias.

Box 6–1: The return on equity in the preliminary decision does not promote the Optimal NEO Position

- The method used in the preliminary decision does not result in a return on equity that is consistent with the allowed rate of return objective (**ARORO**) and does not promote the Optimal NEO Position.
- The evidence before the AER is that the preliminary decision return on equity estimate is too low. In particular, the preliminary decision estimate:
  - Fails a number of its own cross-checks
  - Is below all available evidence as to the return on equity required by investors.
- This outcome is the result of:
  - The preliminary decision relying on the output of the SL CAPM, a model that is known to produce biased estimates, without correcting for that bias
  - The preliminary decision applying this model in a way that does not reflect market practice and which results in the return on equity simply tracking movements in the risk-free rate, and
  - Errors in interpretation and use of key evidence, including empirical evidence relating to the estimation of the market risk premium (**MRP**) and equity beta.
- The ARORO is best achieved through an approach that has regard to estimates from all relevant return on equity models, consistent with our April 2015 proposal and guidance from the AEMC.
- Alternatively, if the AER is to continue relying solely on the SL CAPM, it must adjust its estimates of the MRP and equity beta in order to ensure that its estimate of the return on equity is consistent with the ARORO and reflects prevailing market conditions, including by overcoming known biases with that model.

6.3 GAMMA

136. Gamma represents the value of imputation credits or ‘franking credits’ to investors. These credits are provided to investors for tax paid at the corporate level to offset against their personal income tax.[61] If these credits are highly valued, the return investors expect by way of dividends and capital gains is lower than it might otherwise be.

137. Gamma is a function of the extent to which imputation credits created when companies pay tax are distributed to investors (‘distribution rate’) and the value of distributed imputation credits to investors who receive them (‘theta’).

138. Consistent with the Rate of Return Guideline, we have calculated gamma using a distribution rate of 0.7. However, we have used a theta value of 0.35 which is lower than that favoured by the AER in its guideline and in the preliminary decision. Consistent with expert advice[62] and previous regulatory practice, our proposed value for theta represents the best estimate of the value of imputation credits to investors, rather than the rate of utilisation or their notional face value or potential value. As a result, our value for gamma places a lower value on these credits than that favoured by the AER in its Rate of Return Guideline and preliminary decision.

139. We consider it is in our customers’ long-term interests for investors to be sufficiently compensated for the costs of investing in the benchmark efficient firm (including for tax net of the value they ascribe to imputation credits).

[61] Australia has had an imputation tax system since 1 July 1987. It exists to avoid investors’ corporate profits being taxed twice.

[62] See discussion of these reviews and our gamma proposal in Attachment 6-1.

If they are undercompensated, we may not be able to fund the investments required to provide services that our customers value. For this reason, as outlined in Box 6-2 and explained in detail in Attachment 6-1[63], the preliminary decision does not promote the Optimal NEO Position.

Box 6–2: The approach used to estimate gamma in the preliminary decision does not promote the Optimal NEO Position

- The method used in the preliminary decision to estimate gamma:
  - Does not reflect the value of imputation credits to investors, meaning that the reduction to the overall return to account for imputation credits is too large
  - Is premised on an incorrect interpretation of the NER as the preliminary decision seeks to estimate gamma on a "pre-personal-costs" basis, which is equivalent to estimating gamma as the utilisation of imputation credits, rather than their value to investors.
- As a result, the preliminary decision errs in its use of evidence in relation to gamma because it:
  - Uses equity ownership rates and redemption rates as direct evidence of the value of distributed credits (theta), when in fact these are no more than an upper bound (or maximum) for this value
  - Concludes that market value studies can reflect factors, such as differential personal taxes and risk, which are not relevant to the task of measuring theta. Rather, market value studies are in fact direct evidence of the value of imputation credits to investors.
- The preliminary decision estimate of gamma of 0.4 is inconsistent with a proper interpretation of the empirical evidence:
  - Both tax statistics and equity ownership data indicate that the value of distributed imputation credits (theta) should be no higher than 0.45, and therefore that gamma can be no higher than 0.3
  - The best evidence as to the value of imputation credits—from SFG's updated dividend drop-off study—indicates that theta is approximately 0.35 and, therefore, that gamma is 0.25. Our submission duly reflects this.

6.4 PROPOSED RETURN ON DEBT

140. Our proposed return on debt for the first year of the 2016 regulatory period is 7.77% (compared to 9.99% for the 2011 regulatory period) and accounts for 60% of our proposed rate of return. We propose that the return on debt be updated in later years of the 2016 regulatory period in accordance with the method and formulae set out in Attachment 6-1.

6.4.1 APPROACH WE USED TO CALCULATE PROPOSED RETURN ON DEBT

141. To estimate our proposed return on debt, we considered the riskiness of investments in our distribution services, and then observed the price and promised payments on observed bonds for firms with similar levels of risk.

142. Historically, the AER has estimated the benchmark return on debt by observing the current price and promised payments on observed bonds 'on the day'.[64] However, the Rate of Return Guideline proposes implementing a new approach that involves:

[63] Attachment 6-1 is supported by Attachments 6–2 to 6–12.

- Observing historical prices and promised payments for up to 10 years (a 'trailing average' portfolio approach)
- Updating this annually using the 10 most recent years of observations
- Using yield estimates from an independent third-party service provider for a 10-year debt term with a BBB+ credit rating
- Gradually transitioning to this approach from the 'on the day' approach over a 10-year period.

143. We support the AEMC's changes to the NER and many elements of the AER's proposed approach to calculating the return on debt. Consistent with this approach, we used a 10-year 'trailing average' to calculate our proposed return on debt, and propose that this calculation be updated annually.[65] In our view, this provides greater stability in network prices (which our customers prefer) relative to the 'on the day' approach and better aligns the calculation of the return on debt with efficient debt procurement practices of benchmark firms. Therefore, we consider this approach to calculating the return on debt promotes the Optimal NEO Position.

144. Conversely, we have concerns that the method adopted in the preliminary decision for transitioning to the trailing average approach is unlikely to best promote the Optimal NEO Position. As outlined in Box 6-3 and explained in detail in Attachment 6-1, there are material concerns with the preliminary decision's transition to the trailing average estimation method and the interpretation of what comprises efficient debt financing practice.

145. We consider that our proposed allowance for the return on debt is conservative, in the sense that it is likely to under-state efficient financing costs. This is because we do not include any allowance for a new issue premium (i.e. the additional cost associated with raising new debt) and we have accepted the preliminary decision allowance for debt raising costs, which excludes certain costs associated with early refinancing and liquidity maintenance. Although we consider these to be part of the efficient cost of rising and financing debt, we have not included any allowance for them.

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64 AER, *Rate of return guideline*, December 2013, p 4.

65 This would result in changes to the X-factors and changes to the levels of our network tariffs. Although we prefer the hybrid approach, we adopt the trailing average approach in our proposal (consistent with the rate of return guideline).

Box 6–3: The return on debt in the preliminary decision does not promote the Optimal NEO Position

- The method used in the preliminary decision will not deliver a return on debt estimate which contributes to the achievement of the ARORO and will not to promote the Optimal NEO Position.
- The method used in the preliminary decision to transition to the trailing average estimation method will lead to a return on debt allowance that is below the efficient financing costs of a benchmark efficient entity. In particular:
  - The approach proceeds on the incorrect premise that efficient financing practice is the practice that would have emerged under the previous regulatory approach to estimating the return on debt. The correct approach is to identify the efficient financing practice of a benchmark entity operating in a workably competitive market
  - The preliminary decision accepts that efficient practice in the absence of regulation is to have a staggered portfolio of fixed rate debt
  - Given that efficient financing costs are those associated with a staggered portfolio of fixed rate debt, immediate implementation of the trailing average will provide for an allowance that reflects efficient financing costs. Conversely, application of a transition will lead to an allowance that does not reflect efficient debt financing costs
  - Even if the AER's view – outlined in the preliminary decision – of efficient financing costs is correct, it has applied the wrong transition. On the AER's view of efficient financing costs, a hybrid transition would be the correct form of transition. Application of the AER's transition would lead to a mismatch between efficient financing costs and the regulatory allowance on the debt risk premium (**DRP**) component.
- The AER has erred by setting the credit rating for energy network businesses at BBB+, contrary to empirical evidence. The current evidence (including analysis by Professor Lally) indicates a benchmark credit rating of BBB to BBB+. Given that the appropriate credit rating assumption is BBB to BBB+, use of a broad BBB band data series is entirely appropriate (it is not favourable to JEN, as suggested in the preliminary decision).

7. CAPITAL EXPENDITURE FOR DISTRIBUTION SERVICES

Table 7–1: Overview of our response to the preliminary decision on forecast capital expenditure for distribution services

Components of forecast capital expenditure	Our response to the preliminary decision
Augmentation expenditure	✗
Connections expenditure	≈
Customer contributions	✓
Replacement expenditure	✓
Non-network (IT and other) expenditure	✓
Capitalised overheads	✓
Peak demand forecast	✓
Customer number forecast	✗

Key messages

- We have developed our capital expenditure forecasts for the 2016 regulatory period in accordance with the NER requirements, and to reflect our customers' stated preference for us to maintain our current safety and service levels.
- We have forecast total capital expenditure for distribution services[66] of $863m (including capitalised overheads) for the 2016 regulatory period which is:
  - $161m or 19% more than we spent in the 2011 regulatory period, largely due to:
    - Targeted investments to replace our oldest failure-prone assets and strengthening parts of the network exposed to higher bushfire risk
    - The forecast increase in customer-initiated connections due to new housing developments and the redevelopment of some large industrial sites
    - The need to provide the incremental network capacity required to safely and reliably meet forecast growth in residential and business electricity demand within growth corridors of our network
  - 3% higher than our April 2015 proposal, reflecting additional capital expenditure for the Power of Choice program and to report actual Regulatory Information Notice (**RIN**) data
  - 12% higher than the preliminary decision, reflecting inclusion of:

[66] As outlined in section 2.1, our distribution services are those classified by the AER as Standard Control Services.

- Augex projects for the Flemington and Sunbury zone substation upgrades
- Repex for the Preston Conversion project
- Changes to projects at the Melbourne Airport precinct
- Expenditure for the Power of Choice program.

- We welcome the preliminary decision’s recognition of:
  - The need to augment our network[67]
  - The robustness of the method used to provide a realistic expectation of demand forecasts[68]
  - The need for increased repex to manage the deterioration in the condition of our assets as they reach the end of their economic life[69]
  - Our non-network forecast being a reasonable reflection of efficient cost[70]
  - Our overall efficiency and that our combination of operating expenditure and capital expenditure does not reveal any material inefficiency.[71]
- We have considered the preliminary decision’s concerns with three of our key programs:
  - Flemington zone substation upgrade – we have revised our estimate downwards from $10.6m to $7m (including capitalised overheads) reflecting an alternative and cheaper option
  - Sunbury zone substation upgrade – we demonstrate that JEN has selected the most prudent and efficient option to alleviate capacity constraints in this substation
  - Preston Conversion – we have addressed the preliminary decision concerns, particularly on the options and timing for this project, and have reclassified the Preston Conversion project from augex to repex consistent with the preliminary decision’s suggestion.
- We have reclassified the Melbourne Airport precinct project as connections capital expenditure and updated our estimate based on the current requirements.
- We have thoroughly assessed how best to prudently deliver our proposed capital expenditure program to ensure that the cost of our investments is minimised and timing is optimised. We are confident the program represents the level of expenditure necessary to comply with applicable requirements in the NER, to efficiently meet our obligations and customers’ expectations, and best promote the Optimal NEO Positon.

146. Forecast capital expenditure is a key input to the return on and of capital components of our revenue requirement (See section 5.1). The NER require[72] that we propose the total capital expenditure necessary to provide our distribution and metering services in each year of the 2016 regulatory period, and meet the capital expenditure objectives set out in the NER. These objectives include meeting or managing our customers’

67 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Overview*, October 2015, p 35.

68 Ibid, p 6-40.

69 Ibid, p 6-21.

70 Ibid, p 6-10.

71 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 7 – Operating expenditure*, October 2015, p 7-34.

72 NER cl. 6.5.7(a).

expected demand, and complying with all relevant regulatory obligations and requirements (including those related to our service levels).[73]

147. This chapter provides an overview of our revised forecast capital expenditure for distribution services in the 2016 regulatory period and provides further information about this expenditure as required by the NER and AER,[74] including our proposed capital expenditure programs.

148. In developing our capital expenditure forecast, we are guided by the requirements in the NER, as well as the AER's guidelines, the preliminary decision and our customers' preferences. We also take into account changes occurring, or anticipated in the energy market over the 2016 regulatory period and beyond.

7.1 OVERVIEW OF FORECAST CAPITAL EXPENDITURE FOR DISTRIBUTION SERVICES

149. Our forecast of capital expenditure for our distribution services over the 2016 regulatory period is outlined in Table 7–2.

Table 7–2: Forecast capital expenditure for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
April 2015 proposal	158.24	183.64	177.13	167.60	154.56	**841.17**
Preliminary decision	150.23	161.81	154.69	158.68	148.13	**773.55**
This submission	167.75	203.84	169.32	168.49	153.12	**862.53**

(1) Distribution services capital expenditure above is gross capital expenditure and includes capitalised overheads.

(2) JEN's April 2015 proposal (inclusive of capitalised overheads) is included in section 2.1 of Attachment 7-3 of our April 2015 proposal.

150. The forecast capital expenditure for distribution services over the 2016 regulatory period shown in Table 7–2 is $161m (including capitalised overheads), or 19% more than we spent over the 2011 regulatory period. The main drivers of this increase are to:

- Address safety-related recommendations from the independent safety regulator, Energy Safe Victoria (**ESV**) by replacing the oldest and most failure-prone assets in our network and strengthening parts of the network exposed to higher bushfire risk
- Meet the forecast increase in customer-initiated connections due to new housing developments and the redevelopment of some large industrial sites that have closed, or are expected to close during the 2016 regulatory period
- Provide the incremental network capacity required to safely and reliably meet forecast growth in residential and business electricity demand within growth corridors of our network
- Replace some SCADA and billing IT systems that have come to the end of their useful or economic life, and retire applications and technologies that have become redundant as new systems replace their business and technical functions.

151. Table 7–2 is $21m (including capitalised overheads) or 3% more than our forecast capital expenditure in our April 2015 proposal. The main driver of this increase is $25m of additional capital expenditure forecast

[73] NER cl. 6.5.7(a).

[74] NER cl. 6.5.7 and schedule s 6.1.1; AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, December 2013 and RIN cl. 3.

associated with the AEMC's Power of Choice program. This includes additional capital expenditure for rule changes relating to:

- Metering competition and the shared market protocol
- Customer access to data
- Distribution network pricing.

152. We have also reviewed our 13 July 2015 submission in which we proposed an additional $19m operating expenditure step change for reporting actual RIN data, through this review we have able to scale back our operating expenditure claims to $5.88m however we will require an additional $2.2m (direct cost) under this alternative approach.

153. The forecast capital expenditure for distribution services over the 2016 regulatory period shown in Table 7–2 is $90m (including capitalised overheads) or 12% more than the capital expenditure allowed in the preliminary decision. This reflects inclusion of:

- Augex associated with the Flemington and Sunbury zone substation upgrades
- Repex for the Preston conversion project
- Changes to capital expenditure projects at Melbourne Airport
- Expenditure for the Power of Choice program.

154. Our submission represents a prudent and efficient level of expenditure required to meet our obligations and requirements, and maintain existing service levels for the 2016 regulatory period. We have thoroughly assessed how best to prudently deliver our proposed capital expenditure program to ensure that the cost of our investments is minimised and timing is optimised. The program represents the level of expenditure necessary to comply with requirements in the NER,[75] efficiently meet our obligations and customers' expectations, and promote the long-term interests of our consumers. For these reasons it will best promote the Optimal NEO Position.

7.2 FORECAST AUGMENTATION EXPENDITURE FOR DISTRIBUTION SERVICES

155. Our proposed augmentation capital expenditure (or **augex**) for our distribution services is outlined in Table 7–3.

Table 7–3: Forecast augex for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
April 2015 proposal	18.50	48.28	40.53	22.95	10.35	**140.63**
Preliminary decision	12.17	31.74	26.65	15.09	6.81	**92.46**
This submission	10.66	37.91	27.76	17.86	10.31	**104.49**

(1) JEN's distribution services augex above are direct costs (excludes capitalised overheads).
(2) JEN's April 2015 proposal (inclusive of capitalised overheads) is included in section 3.3 of Attachment 7-3 of our April 2015 proposal.

156. Table 7–3 shows that our forecast of augmentation capital expenditure for the 2016 regulatory period is $36m (direct costs) or 26% lower than our April 2015 proposal reflecting:

75 Including the capital expenditure objectives in NER cl. 6.5.7.

- Slightly lower forecast capital expenditure for the Flemington zone substation upgrade
- Our reclassification of the Preston Conversion project as repex and Melbourne Airport precinct as connections capital expenditure

157. Table 7–3 also shows that our forecast of augmentation capital expenditure for the 2016 regulatory period is $12m (direct costs) or 13% higher than the preliminary decision reflecting:

- Our inclusion of forecast capital expenditure for the Flemington and Sunbury zone substation upgrades
- Lower capital expenditure resulting from categorising some expenditure relating to the Melbourne Airport precinct project from augex to connections capital expenditure and categorising expenditure for the Preston area conversion project from augex to repex.

158. The preliminary decision:

- Was satisfied that JEN's network planning method and criteria reflects good industry practice
- Accepted that JEN's maximum demand forecasts likely reflect a realistic expectation of demand over the 2016 regulatory period and accepted JEN's demand forecasts at the system level and localised demand forecasts for the relevant augmentation projects
- Accepted that our proposals to build Craigieburn zone substation, to install Rapid Earth Fault Current Limiter (**REFCL**) systems, and to augment low and high voltage feeders, and distribution transformers satisfied the capital expenditure criteria and are prudent
- Accepted our proposed $5.95m (direct costs) to split the existing 66kV sub-transmission loop to the Melbourne Airport precinct
- Was not satisfied that we proposed the most prudent and efficient option to address the need for the augex investments in the Sunbury zone substation upgrade, the Flemington zone substation upgrade, and the proposed Preston Conversion project; nor that we adequately considered non-network options to defer major augex.

159. Accordingly, the preliminary decision substituted an estimate of JEN's total augex requirements for the 2016 regulatory period of $92.5m (direct costs).

160. We welcome the preliminary decision's recognition of the integrity of our network planning approach and our demand forecasts, and the need for various augmentations to our network. In particular, we welcome the preliminary decision's acknowledgement that our proposed Craigieburn zone substation augex and capital expenditure for installing REFCL satisfy the capital expenditure criteria and support the Optimal NEO Position.

161. In response to the preliminary decision we have:

- Updated our peak demand forecasts to reflect the most current data available (see Attachment 7-3)
- Revised our augex forecast for Flemington zone substation down from $8.2m to $7m (direct costs) reflecting an alternative and cheaper option that has become available following detailed design engineering completed after submitting our April 2015 proposal (see Attachments 7-1, 7-13 and 7-14)
- Demonstrated that the Sunbury zone substation upgrade option selected by JEN is the preferable option to alleviate capacity constraints in this substation and maximise the net benefit to our customers (see Attachments 7-1, 7-11, 7-12)

- Provided more material on the options and timing for the Preston Conversion project. Further, we have reclassified the project from augex to repex consistent with the preliminary decision's commentary that the project drivers over the 2016 regulatory period are primarily condition related (see Attachments 7-1, 7-15, 7-20 and 7-21).

162. Updated our estimate for Melbourne Airport and reclassified the project from augex to connections capital expenditure given the project will be fully funded through future tariffs (see Attachments 7-1 and 7-19).Further detail on our proposed augmentation capital expenditure for our distribution services is provided in Attachments 7-1 to 7-21.

7.3 FORECAST CONNECTIONS AND CUSTOMER CONTRIBUTIONS CAPITAL EXPENDITURE FOR DISTRIBUTION SERVICES

163. Table 7–4 below sets out our April 2015 proposal and submission connections and customer contributions forecast for distribution services. This outlines that our net connections capex forecast—the component of connections capex funded by our broader customer base—is lower than our April 2015 proposal.

Table 7–4: Forecast connection and customer contribution capex for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
April 2015 proposal						
Gross connections	45.07	44.24	48.07	43.60	46.83	**227.80**
Less customer contributions	26.45	25.58	27.34	25.70	27.59	**132.65**
Net forecast	**18.62**	**18.66**	**20.73**	**17.90**	**19.24**	**95.15**
This submission						
Gross connections	45.76	52.89	41.71	43.23	45.51	**229.11**
Less customer contributions	29.66	31.88	29.21	30.29	32.20	**153.24**
Net forecast	**16.10**	**21.01**	**12.49**	**12.95**	**13.31**	**75.87**

(1) Distribution services connections and customer contributions capital expenditure in Table 7–4 above include capitalised overheads.
(2) JEN's April 2015 proposal (inclusive of capitalised overheads) is included in section 3.2 of Attachment 7-3 of our April 2015 proposal.

164. Table 7–4 shows that our forecast of connections capital expenditure for the 2016 regulatory period is similar to our April 2015 proposal. Our forecast of customer contributions capital expenditure for the 2016 regulatory period is $21m (including capitalised overheads) or 16% higher than our April 2015 proposal reflecting:

- An updated contribution rate to reflect the NER Chapter 5A method for calculating customer contributions
- The most current customer number forecast
- A slight increase in the Melbourne Airport Project contribution following an update to the project scope.

165. In addition to the drivers of higher customer contributions identified above, our submission includes 29.9m (including capitalised overheads) of customer contributions for special capital works which was omitted in the preliminary decision.

166. We welcome the preliminary decision's recognition that our:

- Connection forecast is a reasonable estimate based on our actual and forecast customer contributions and historical spend, and phased approach to produce forecast customer contributions
- Residential and commercial/industrial sector volume growth rates represent a realistic expectation of connection activity
- Assumed unit rates are reasonable
- Forecast customer contributions are consistent with the requirements set out in Guidelines 14[76] and 15,[77] and reasonably reflect the contributions we are likely to receive in the 2016 regulatory period.

167. While we welcome the preliminary decision on our connections and customer contributions forecast, we have resubmitted our customer contributions included in April 2015 proposal given our concern that the preliminary decision may have misinterpreted our customer connections forecast and does not promote the Optimal NEO Position.

168. The preliminary decision did not approve our proposed $8.56m (direct costs) installation of a new 66kV sub-transmission line to Melbourne Airport included in the connections forecast. We have updated this forecast given ongoing discussions with Melbourne Airport, on their requirements. Attachment 7-19 provides further details on the requirements and cost estimates for the Melbourne Airport project.

169. Consistent with the AER's expectations that we update our maximum demand forecasts for latest information, JEN has revised its residential and commercial/industrial sector volume growth rates (see Attachment 7-3, 7-4 and 7-5). Our revised customer growth are slightly higher resulting overall in increased connection capital expenditure forecast for the 2016 regulatory period (see Attachment 7-7).

170. Further detail on our proposed connections capital expenditure and customer contributions for our distribution services is provided in Attachments 7-1 to 7-2.

7.4 FORECAST REPLACEMENT CAPITAL EXPENDITURE FOR DISTRIBUTION SERVICES

171. Our proposed replacement capital expenditure for our distribution services is outlined in Table 7–5.

Table 7–5: Forecast replacement capital expenditure for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
April 2015 proposal	36.42	40.85	39.29	52.99	54.00	**223.54**
Preliminary decision	36.42	40.85	39.29	52.99	54.00	**223.54**
This submission	42.68	48.20	50.25	59.35	55.11	**255.60**

(1) Distribution services replacement capital expenditure above are direct costs (excludes capitalised overheads).

(2) JEN's April 2015 proposal (inclusive of capitalised overheads) is included in section 3.1 of Attachment 7-3 of our April 2015 proposal.

172. Table 7–5 shows that our forecast of repex for the 2016 regulatory period is higher than our April 2015 proposal and the preliminary decision, reflecting our reclassification of the Preston Conversion project from augex to repex.

[76] ESC, *Electricity industry guideline no. 14, provision of services by electricity distributors, issue 1*, April 2004.

[77] ESC, *Electricity industry guideline no. 15, connection of embedded generation, issue 1*, August 2004.

173. We welcome the preliminary decision's recognition of the need for increased replacement expenditure to manage the deterioration in the condition of our assets as they reach the end of their economic life[78], and the acceptance of our proposed repex of $224m (direct costs) as an amount that reasonably reflects the capital expenditure criteria.

174. Our submission adopts the preliminary decision on our business as usual repex and repex for other categories, and we have reclassified the Preston Conversion project from augex to repex. We note that our repex, including the Preston Conversion project is lower than the AER's modelled repex in its preliminary decision.

175. Further detail on our proposed replacement capital expenditure for our distribution services is provided in Attachments 7-10 and 7-21.

7.5 CAPITALISED OVERHEADS FOR DISTRIBUTION SERVICES

176. Our proposed capitalised overheads for our distribution services are outlined in Table 7–6.

Table 7–6: Forecast capitalised overheads for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
April 2015 proposal	32.05	32.89	33.77	34.62	35.49	**168.82**
Preliminary decision	31.39	31.56	32.28	34.00	35.17	**164.40**
This submission	31.94	33.16	33.26	34.71	35.51	**168.58**

177. The preliminary decision did not accept our proposed capitalised overheads of $168.8m, but instead reduced these to account for the lower substituted capital expenditure.

178. We accept and adopt the preliminary decision's model and approach to adjusting the capitalised overheads forecast for revised total capital expenditure forecast, and have reflected this approach in our submission. Further detail on our proposed capitalised overheads for our distribution services is provided in Attachment 7-1.

7.6 FORECAST NON-NETWORK CAPITAL EXPENDITURE FOR DISTRIBUTION SERVICES

179. Our non-network capital expenditure includes expenditure on information and communications technology (**ICT**), and other capital expenditure on motor vehicles, tools and equipment, buildings and property. Our proposed non-network capital expenditure for our distribution services is outlined in Table 7–7.

Table 7–7: Forecast non-network capital expenditure for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
April 2015 proposal	38.48	27.01	26.35	24.37	20.99	**137.20**
Preliminary decision	38.48	27.01	26.35	24.37	19.67	**135.87**
This submission	49.24	42.93	26.12	24.08	19.36	**161.74**

(1) Distribution services non-network capital expenditure above are direct costs, JEN does not allocate overheads to non-network capital expenditure.

78 AER, *Preliminary decision, Jemena distribution determination - 2016 to 2020, Overview*, p 16 and p 21.

(2) JEN's April 2015 proposal (inclusive of capitalised overheads) is included in section 3.4 of Attachment 7-3 of its April 2015 proposal.

180. Table 7–7 shows that our forecast of non-network capital expenditure for the 2016 regulatory period is slightly higher than our April 2015 proposal and the preliminary decision, reflecting new capital expenditure for the AEMC's Power of Choice program.

181. We welcome the preliminary decision's acceptance of forecast non-network capital expenditure of $137.2m (direct costs).

182. The preliminary decision accepted that:

- ICT capital expenditure is likely to reflect the high level drivers of expenditure, and as such reflect a reasonable estimate of efficient costs
- Motor vehicles capital expenditure is likely to reflect the high level drivers of expenditure, and represents a reasonable estimate of efficient costs
- Broadmeadows depot redevelopment capital expenditure reasonably reflects the efficient costs of a prudent operator as evidenced by JEN's demonstrated need for further investment to redevelop the Broadmeadows site following completion of the new Tullamarine depot in 2014 and the supporting financial case.

183. We note that the preliminary decision included the forecast property disposal included in the Broadmeadows project business case for the 2016 regulatory period.

184. We note that since the release of the preliminary decision, the AEMC released its final rule changes associated with the Power of Choice program including:

- Metering competition
- Customer access to data, and
- Distribution network pricing.

185. A rule change for shared market protocol (within the Power of Choice program) is not expected until May 2016. We have included an additional $25m (direct costs) forecast capital expenditure in our non-network capital expenditure forecast for expenditure required to give effect to these rule changes.

We have accepted the preliminary decision of our non-network capital expenditure forecast, including the treatment of proceeds from partial sale of the Broadmeadows depot. We have also added to the preliminary decision additional capital expenditure of $25m (direct costs) for the AEMC's Power of Choice program and $2.5m for reporting actual RIN data. Further detail on our proposed non-network capital expenditure for our distribution services is provided in Attachment 7-1.

8. OPERATING EXPENDITURE FOR DISTRIBUTION SERVICES

Table 8–1: Overview of our response to the preliminary decision on forecast operating expenditure for distribution services

Components of forecast operating expenditure	Our response to the preliminary decision
Base year efficiency	✔
Rate of change	✘
Step changes	✘

Key messages

- We developed our operating expenditure forecasts for the 2016 regulatory period using an approach consistent with the operating expenditure objectives from the NER. We also took account of our customers' preference for us to maintain our current safety and service levels and to adapt our services to the changing energy market.
- We proposed 2014 as our **base year** because we consider it an efficient 'launch point' to forecast our operating expenditure. This is supported by our comparable productivity performances, highlighted in the AER's most recent annual benchmarking report. We welcome the preliminary decision's recognition of our efficiency and our responsiveness to the incentive framework which provides us with incentives to continually improve our efficiency and share these with our customers—with these efficiencies calculated to be $24.8m ($2015) over the 2011 regulatory period through the EBSS.
- We are concerned that the preliminary decision finds that there are very few changes in the external environment that require a step change in operating expenditure[79]. We accept the preliminary decision's approach to six of the 13 operating expenditure **step changes** we proposed in our April 2015 proposal—including rejection of step changes in relation to demand management programs, two that are more appropriately incorporated in the base level of operating expenditure (developing the regulatory proposal and further customer engagement initiatives) and the uncertain costs associated with changes to the ESV code of practice changes. However the preliminary decision's rejection of the remaining seven step changes proposed by JEN—including relating to RIN reporting requirements, vegetation management and vulnerable customer initiatives valued by our customers—does not promote the Optimal NEO Position given that JEN must be given an opportunity to recover its efficient costs of new obligations imposed by new laws and regulatory instruments. The requirements imposed by these changes are clear and the costs of compliance are significant.
- In addition to the operating expenditure step changes raised in the April 2015 proposal, JEN raises additional operating expenditure step changes relating to an increase in GSL obligations, and new obligations from the AEMC's Power of Choice program, giving consumers options in the way they use electricity.
- In developing the operating expenditure **rate of change**, the preliminary decision substituted JEN's real price growth (labour and material costs) forecasts with its own and applied its own method for scale escalation. While we accept the real price growth forecasts and its new method, we are concerned that the preliminary decision inconsistently applies customer number forecasts and uses an incorrect demand forecast for ratcheted demand.
- The preliminary decision also fails to support allocative efficiency by reallocating operating expenditure costs that

[79] AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Overview*, October 2015, p 22.

JEN proposed belong in distribution services back to metering services.

186. Forecast operating expenditure is one of the building block costs used to calculate the ARR (see chapter 5). We must propose the total operating expenditure we will require to provide our distribution services in each year of the 2016 regulatory period, and meet the operating expenditure objectives set out in the NER and Victorian metering obligations.[80] These objectives include meeting or managing our customers' expected demand, and complying with all relevant regulatory obligations and requirements (including those related to our safety and service levels).[81]

187. Our forecast operating expenditure for distribution services includes the costs of operating and maintaining our physical assets (for example, poles, wires, and computer and billing systems), responding to emergencies (such as fallen trees on our lines), and performing related customer functions and providing billing information to retailers.

188. We forecast operating expenditure in accordance with the AER's 'base, step and trend" approach. This involves using three key inputs: our revealed efficient 2014 base year costs; forecast step changes for new activities; and forecast expected rate of change in operating costs. This chapter provides an overview of our revised forecast operating expenditure for distribution services in the 2016 regulatory period as required by the NER and the AER, as well as an overview of the three key inputs.

189. In developing our operating expenditure forecast, we are guided by the requirements in the NER, as well as the AER's guidelines, the preliminary decision and our customers' preferences. We also took into account changes occurring in the energy market, or anticipated to occur, over the 2016 regulatory period and beyond. Further detail of our revised forecast operating expenditure for distribution services is provided in Attachment 8-1.

8.1 OVERVIEW OF FORECAST OPERATING EXPENDITURE

190. Our forecast operating expenditure for distribution services over the 2016 regulatory period is outlined in Table 8–2.

Table 8–2: Proposed forecast operating expenditure for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
April 2015 proposal	95.37	95.36	98.51	103.18	106.60	**499.01**
Preliminary decision	76.42	76.70	77.68	79.00	80.26	**390.07**
This submission	93.81	91.83	93.28	95.59	96.38	**470.89**

191. The forecast operating expenditure in this submission for our distribution services over the 2016 regulatory period is $63.6m ($2015) or 17% more than we spent over the 2011 regulatory period. The main drivers of this increase are:

- Unavoidable upward pressure on operating expenditure, including forecast real increases in our key input costs, forecast growth in key network characteristics such as ratcheted maximum demand and circuit length as well as customer numbers, with these factors representing $30.4m ($2015) or 8% of the increase in our forecast of operating expenditure over the 2016 regulatory period

80 Per AMI Order in Council.

81 NER cl. 6.5.6.

- Additional inspection, maintenance, customer engagement and vulnerable customer assistance programs to ensure we continue to meet safety requirements and our customers' expectations, with these step changes in operating expenditure representing $21.8m ($2015) or 6% of the increase in our forecast operating expenditure over the 2016 regulatory period, and
- Additional regulatory reporting requirement through the AER's Category Analysis and Economic Benchmarking RINs representing $5.9m ($2015) or 2% of the increase in our forecast of operating expenditure over the 2016 regulatory period.

192. In addition to these increases in our operating costs, distribution service operating expenditure is also affected by reclassification of certain costs. These reclassifications represent a $46.0m ($2015, excluding real cost escalation) or 13% of the increase in our forecast of operating expenditure over the 2016 regulatory periods, and comprise:

- supply abolishment costs (up to 100 amps) as distribution services consistent with the AER's F&A paper[82]
- certain network systems and customer support costs[83] that were temporarily recoverable under the AMI Order in Council now reverting back to the distribution services cost base given that the AMI Order in Council ends on 31 December 2015, and these activities are a necessary component of our distribution services in the 2016 regulatory period.

193. The forecast operating expenditure for distribution services shown in Table 8–2 is $28.1m ($2015) or 5.6% less than our forecast operating expenditure in our April 2015 proposal. The main drivers of this decrease are refinements to our:

- **Base year** (down $17.7m, $2015)—taking into account refinement to lower our estimate of AMI Order in Council costs reclassified to distribution services (following feedback in the preliminary decision)
- **Step changes** (down $3.3m, $2015)—where we:
  - Removed four step changes (regulatory proposal costs, customer engagement costs, ESV/VESI code of practice changes and overhead switch inspection), consistent with the preliminary decision
  - Added three step changes (ESC GSL obligations, costs associated with the AEMC's Power of Choice program and increased operating expenditure associated with the Victoria now adopting elements of NER Chapter 5A to connect customers)
  - Refined our estimates, reducing the forecast for two step changes (enclosed substation inspection and vegetation management and RIN reporting capability).
- **Rate of change** (down $4.0m, $2015)—where we agreed with the preliminary decision in relation to the real price growth, no productivity growth and output growth drivers method but included our forecast of the customer numbers and ratcheting peak demand input drivers
- **Category specific forecasts** (down $4.1m, $2015)—agreeing with the AER's debt raising cost benchmark.

194. The forecast operating expenditure for distribution services over the 2016 regulatory period shown in Table 8–2 is $80.8m ($2015) or 20.5% more than the allowance in the preliminary decision. The main drivers of this increase are refinements to:

82 AER, *Final Framework and approach for the Victorian Electricity Distributors, Regulatory control period commencing 1 January 2016*, 24 October 2014, p 43 and table 8.

83 These reclassified activities mainly comprise network systems IT staff costs for running the: connection point management system, data reporting, business to market gateway, and a share of the operations of the meter data management system and meter network management system associated with network billing. They also include lesser amounts for customer support, network billing, and reporting and finance.

- **Base** year (up $40.6m, $2015)—where we included costs associated with metering services required for our core distribution services, and updated the 2015 inflation forecast to 1.75% (compared to the preliminary decision placeholder assumption of 2.50%)
- **Step** changes (up $24.6m, $2015)—where we believe we require funding for:
  - Additional inspection, maintenance, customer engagement and vulnerable customer assistance programs to ensure we continue to meet safety requirements and our customers' expectations, with these step changes
  - Complying with new obligations in relation to RIN reporting and vegetation management to reflect the clarified expectations provided by the AER and ESV
  - Complying with an increase in GSL obligations and new obligations relating to the Australian Energy Market Commission's Power of Choice program on giving consumers options in the way they use electricity.
- **Rate of change** (up $15.6m ,$2015), mainly due to differences in the escalation rates (within our output growth) for
  - Ratcheted maximum demand (see Attachment 7-4)
  - Customer numbers (see Attachment 7-7).
- **Category specific forecasts** (up $0.1m, $2015), due to higher debt raising costs required to fund additional capital expenditure related to the Power of Choice program.

195. We have undertaken a thorough assessment to determine that our forecast operating expenditure represents the expenditure that would be required to achieve the requirements in the NER,[84] to efficiently meet our obligations and customers' expectations for safe, reliable and responsive distribution network services and promote the Optimal NEO Position.

196. Further detail is set out in Attachment 8-1.

8.2 BASE, STEP, TREND APPROACH

197. Table 8–3 shows JEN's April 2015 proposal and submission operating expenditure forecast using the AER's base, step, trend method, compared with the AER's determined efficient operating expenditure forecast in its preliminary decision.

Table 8–3: Key assumptions used to forecast operating expenditure for our distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
April 2015 proposal						
Base year operating expenditure	85.35	85.35	85.35	85.35	85.35	**426.76**
Step changes	6.62	4.18	4.80	6.94	7.81	**30.34**
Escalation / rate of change	1.99	4.34	6.79	9.25	11.72	**34.10**
Category specific forecasts	1.41	1.48	1.56	1.64	1.72	**7.81**

84 Including the operating expenditure objectives in NER cl. 6.5.6(a).

	2016	2017	2018	2019	2020	Total
Total forecast operating expenditure	**95.37**	**95.36**	**98.51**	**103.18**	**106.60**	**499.01**
Preliminary decision						
Base year operating expenditure	73.70	73.70	73.70	73.70	73.70	**368.49**
Step changes	1.34	0.62	0.40	0.40	0.40	**3.16**
Escalation / rate of change	0.72	1.69	2.86	4.14	5.37	**14.79**
Category specific forecasts	0.66	0.69	0.73	0.76	0.79	**3.63**
Total forecast operating expenditure	**76.42**	**76.70**	**77.68**	**79.00**	**80.26**	**390.07**
This submission						
Base year operating expenditure	81.82	81.82	81.82	81.82	81.82	**409.09**
Step changes	9.42	5.54	4.76	4.76	3.22	**27.71**
Escalation / rate of change	1.90	3.78	5.95	8.22	10.52	**30.37**
Category specific forecasts	0.67	0.70	0.75	0.78	0.81	**3.72**
Total forecast operating expenditure	**93.81**	**91.83**	**93.28**	**95.59**	**96.38**	**470.89**

(1) Forecast operating expenditure includes debt raising costs, which is treated as a category specific forecast.

198. Each component of the base, step, trend method (including category specific costs) is discussed in the sections 8.3 to 8.6 and further explains in Attachment 8-1.

8.3 BASE YEAR OPERATING EXPENDITURE

199. Consistent with our April 2015 proposal and the preliminary decision, this submission uses 2014 as the base year as it is an efficient 'launch point' to forecast our operating expenditure over the 2016 regulatory period, given the comparable productivity performances, highlighted in the AER's most recent annual benchmarking report.[85]

200. We welcome the preliminary decision's recognition of our efficiency[86] and our responsiveness to the incentive framework which provides us with incentives to continually improve our efficiency and share these with our customers. These efficiencies are estimated to be $24.8m ($2015) over the 2011 regulatory period given effect through the EBSS.

201. JEN has adjusted its 2014 base year operating expenditure to remove movements in provisions, non-recurrent costs, and category specific forecasts (GSL payments, demand side management costs and debt raising costs) consistent with the preliminary decision.

202. JEN has then added back costs relating to service reclassification, namely for supply abolishment (consistent with the preliminary decision) and metering costs (using a refined cost allocation which addresses preliminary decision feedback). Lastly, JEN has adopted the AER's method for estimating the 2015 operating expenditure forecast, taking into account the operation of the EBSS, where the last year of the current regulatory period (2015) is estimated so that the incremental gain/penalty under the EBSS for that year is nil.

203. This submission includes a 2015 operating expenditure estimate of $81.8m ($2015).

85 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2015.

86 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 3 − Rate of return, October 2015*, page 7-34.

8.4 STEP CHANGES

204. Step changes include increases or decreases in costs due to new regulatory obligations, or changes in the operating environment that are outside our control. These also include increased operating expenditure when delivering capital expenditure reductions where economically efficient to do so (capital expenditure trade-offs).

205. Our April 2015 proposal included operating expenditure step changes resulting in an increase of $30.3m ($2015) in the 2016 regulatory period to meet new regulatory obligations, respond to changes in our operating environment and address customers' preferences. In addition, in a further submission dated 13 July 2015,[87] JEN proposed two further step changes for:

- Vegetation management obligations - increasing them from $5.6m to $15.9m ($2015)
- RIN reporting obligations - costing $19.7m ($2015),

taking our total step changes to $60.3m.

206. The preliminary decision considered that there are very few changes in the external environment, such as new regulatory obligations, that require a step change in operating expenditure.[88]

207. The preliminary decision:

- Recognised step changes related to the implementation of our new tariff structures
- Managed the additional operating expenditure relating to demand management programs, developing the regulatory proposal and further customer engagement initiatives through other mechanisms (such as inclusion in base year costs)
- Sought further information relating to vegetation management and RIN reporting costs.

208. We are concerned that despite the well documented changes occurring in the energy market and changes in regulatory obligations, the preliminary decision concludes that there are very few changes in the external environment that require a step change in operating expenditure.

209. We accept the preliminary decision's approach to six of the thirteen operating expenditure step changes we proposed in our April 2015 proposal. This includes rejection of step changes in relation to demand management programs (where capital expenditure is traded off against operating expenditure), two incorporated in the base level of operating expenditure (developing the regulatory proposal and further customer engagement initiatives) and the uncertain costs associated with changes to the ESV code of practice changes—to the extent that these changes are more appropriately managed through other mechanisms (such as inclusion in base year costs).

210. However the preliminary decision's exclusion of the remaining seven operating expenditure step changes—including relating to RIN reporting requirements, vegetation management and vulnerable customer initiatives proposed by our customers—does not promote the Optimal NEO Position given:

- There must be an opportunity to recover the efficient costs[89] of new obligations imposed by the legislative and regulatory requirements

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87 JEN, *Submission to Jemena Electricity Network Ltd 2016-20 regulatory proposal*, 13 July 2015.

88 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Overview*, October 2015, p. 22.

89 National Electricity Law (**NEL**). s. 7A(2).

- There should be incentives to pursue operating expenditure efficiencies[90]—including through service inspection and testing and early detection program for pole-top fires—even if the benefits of those efficiencies will not be realised until a later regulatory period
- The preliminary decision failed to justify excluding the costs associated with step change initiatives that have been proposed, consulted open and supported by our customers, such as programs to assist vulnerable customers.

211. Our submission includes an increase of $27.7m ($2015) in the 2016 regulatory period (compared to the 2011 regulatory period) to meet new regulatory obligations and respond to changes in our operating environment and customers' preferences. These costs reflect forecast prudent and efficient operating expenditure not captured by the base year expenditure or trend escalation, where we assessed alternative options to ensure we promote the Optimal NEO Position. Insufficient funding for these step changes will deny us a reasonable opportunity to recover our efficient costs.

212. Table 8–4 outlines JEN's position on the non-confidential step changes.

Table 8–4: Outline of JEN's position on non-confidential step changes[91]

Proposed step change	April 2015 proposal	Preliminary decision	Our response to preliminary decision	This submission
Service inspection and testing program	$6.15m	$0m	The costs of the obligation are not in the base year, therefore, we reiterate our claim to have a reasonable chance to recover our efficient costs	$6.15m
Overhead switch inspection	$2.17m	$0m	We concede the disallowance, at this point in time, due to the low levels of certainty	$0m
Enclosed substation inspection and rectification	$0.77m	$0m	The costs of the obligation are not in the base year, therefore, we reiterate our claim to have a reasonable chance to recover our efficient costs. We have revised our forecast in this submission	$0.56m
Electricity Distribution Price Review	$8.03m	Included in base year operating expenditure	We agree with the preliminary decision's alternative treatment of these costs	$0.0m
Vegetation management	$15.89m	$0m	Disallowed due to uncertainty about the manner in which ESV will enforce the new regulatory requirements and because the estimate is high. We do not accept that the ESV approach alters our legal obligations, but have nonetheless revised downward our forecast in this submission	$6.93m
ESV code of practice changes	$0.93m	$0m	We concede the disallowance, at this point in time, due to the low levels of certainty	$0m

90 NEL, s. 7A(3).

91 In some cases, the preliminary decision position on individual step change items has been agreed to by JEN on the basis that the AER accepts the entirety of JEN's submission. If this is not the case JEN maintains the position on these items as set out in our April 2015 proposal. In other cases, the AER position to disallow amounts as a step change is based on those amounts being permitted to be recovered by JEN in other ways (such as through base year operating expenditure). JEN's acceptance is therefore also subject to the final determination confirming recovery of those amounts. More detail is set out in Attachment 8-2.

Proposed step change	April 2015 proposal	Preliminary decision	Our response to preliminary decision	This submission
Vulnerable customer initiative	$1.01m	$0m	Disallowed due to the ESC's financial hardship review, however we resubmit this as our customers have asked for it	$1.01m
Customer engagement	$0.93m	Included in base year operating expenditure	We agree with the preliminary decision's alternative treatment of these costs	$0m
New technology trial: pole-top fire detection	$1.38m	$0m	Disallowed as benefits do not outweigh cost, however JEN submits the benefits in future regulatory periods outweighs the cost in this regulatory period	$1.38m
Demand management opex/capex trade-off	$0.71m	$0.71m	We agree with the preliminary decision's treatment to approve these opex/capex trade off costs	$0.71m
New tariffs	$2.46m	$2.45m	We agree with the preliminary decision's treatment to approve these costs to meet new obligations	$2.46m
RIN reporting	$19.65m	$0m	Disallowed because the estimate is high. We have revised our forecast in this submission	$5.88m
Increased GSL obligations			We seek an additional step change for new obligations arising since we submitted our April 2015 proposal	$0.89m
Power of choice			We seek an additional step change for new obligations arising since we submitted our April 2015 proposal	$0.88m
Adoption of Chapter 5A			We seek an additional step change for new obligations arising since we submitted our April 2015 proposal	$0.71m

(1) Details on confidential step changes can be found in Attachment 8-2.

213. Further information is set out in Attachment 8-2, including the details on further step changes sought in our submission for changes in GSL obligations in Victoria,[92] Victoria's partial adoption of NER Chapter 5A for connecting customers[93] and fulfilling Power of Choice requirements.

8.5 RATE OF CHANGE

214. In applying its base, step, trend method, the AER adjusts base year operating expenditure for likely changes to operating expenditure (rate of change) over the forecast regulatory period that result from:

- Real price growth

[92] ESC, *Review of the Victorian electricity distributors' guaranteed service level payment scheme, final decision*, December 2015

[93] National Electricity (Victoria) Further Amendment Bill 2015, 8 December 2015

- Output growth
- Productivity growth.

215. The preliminary decision on rate of change does not promote the Optimal NEO Position because it does not provide for a realistic expectation of forecast demand required to achieve the operating expenditure objectives.

8.5.1 REAL PRICE GROWTH

216. In our April 2015 proposal, we proposed a real price growth of 0.98% per year, representing an increase of $11.6m ($2015) in operating expenditure over the 2016 regulatory period.

217. The preliminary decision price growth forecast was on average 0.32% lower than JEN's forecast, at 0.66% per year.

218. We have adopted the preliminary decision position on real price growth method (escalation and weights) and forecast in this submission. Further, whilst we believe that the AER's applied labour rates and zero rate for materials costs are conservative (low), JEN has adopted them in this submission.

8.5.2 OUTPUT GROWTH

219. Our April 2015 proposal put forward an average output growth of 2.43% over the 2016 regulatory period.

220. In the preliminary decision was not satisfied that our:

- Output measures and forecasting method adopted to forecast output growth reflect a realistic expectation of the output growth JEN will experience
- Forecast of customer numbers reflects a realistic expectation of the demand forecast required to achieve the operating expenditure objectives.

221. Our submission:

- Adopts the preliminary decision's output growth measures and weightings of customer numbers, circuit length and ratcheted maximum demand
- Applies the following inputs in calculating the output growth:
  - Customer number growth (see Attachment 7-7)
  - Circuit length from our price reset RIN (consistent with the preliminary decision)
  - Ratcheted demand forecast (see Attachment 7-4).

8.5.3 PRODUCTIVITY GROWTH

222. Our April 2015 proposal put forward productivity growth of 0.89% per year.

223. The preliminary decision adopted Economic Insights' recommendation to apply zero forecast productivity growth for efficient service providers, which we agree with and have adopted in our submission.

8.6 CATEGORY SPECIFIC FORECASTS

224. We add to our adjusted and trended base year forecast category specific forecasts for:

- GSL payments
- Debt raising costs.

225. The preliminary decision agreed to these category specific forecasts and the method applied by JEN. JEN has adopted the preliminary decision for category specific forecasts in its submission.

9. REVENUE REQUIREMENT FOR METERING SERVICES

Table 9–1: Overview of our response to the preliminary decision on our revenue requirements, forecast capital expenditure and forecast operating expenditure for metering services

Components of revenue requirements for metering services	Our response to the preliminary decision
Annual revenue requirement ('building block costs')	✗
Maximal Allowed Revenue ('smoothed' revenue) and X-factors	✗
Metering Asset Base roll-forward	✓
Tax Asset Base roll-forward	✓
Depreciation	✓
Forecast capital expenditure	≈
Forecast operating expenditure	≈

Key messages

- In developing our proposed revenue requirement for our metering services, we complied with all relevant NER requirements, including using a 'building block' approach and the AER's post-tax revenue model. We have also taken account of the changes occurring in the energy market and our customers' priorities and preferences.
- Our proposed ARR for metering services in the 2016 regulatory period is $146.21m. Our proposed ARR promotes the Optimal NEO Position as it provides sufficient revenue to allow us to invest in, operate and maintain our network efficiently and earn a reasonable return on our investment in providing the metering services our customers value over the 2016 regulatory period.
- Our proposed MAR and X-factors for our metering services reflects our intention to pass on the reductions in our costs following the completion of the roll-out of AMI to customers as soon as possible.
- We welcome the preliminary decision's recognition of our efficiency in providing metering services[94] and our approach to determining exit fees in Victoria.[95]
- We have accepted the preliminary decision's position on elements of our forecast capital expenditure and operating expenditure and exit fees, however elements of the preliminary decision are unlikely to promote the Optimal NEO Position including:
  - Meter hardware capital expenditure costs
  - Meter installation capital expenditure costs

[94] AER, *Preliminary decision, Jemena distribution determination 2016 to 2020, Attachment 16 - Alternative control services*, October 2015, p 16-43.

[95] Ibid, p 16-45.

- The treatment of JEN's one-off adjustment
- The approach to escalating our operating expenditure forecasts.

- Our submission includes forecast capital expenditure and operating expenditure that reflect the cost to invest in, operate and maintain our network efficiently in providing the metering services our customers value over the 2016 regulatory period.

226. We propose the 'X-factors' that determine the average change in our network revenue for metering services in each year of the regulatory period. The X-factors should reflect the average annual changes in our revenue (on top of changes in the CPI) necessary for us to invest in, operate and maintain our network efficiently, and earn a reasonable return on our investment in this network over the period.

227. We calculate the X-factors by:

- Calculating our ARR for each year of the 2016 regulatory period using a building block approach, including our proposed:
  - Returns on and of capital (including opening capital base, forecast capital expenditure, rate of return and regulatory depreciation)
  - Operating and tax costs
  - Other revenue adjustments, including any rewards or penalties from the incentive schemes outlined in chapter 3.
- Calculating the X-factors for each year of the 2016 regulatory period to recover the MAR.

228. This chapter provides an overview of our ARR, MAR and X-factors for metering services as well as key inputs such as forecast capital expenditure and forecast operating expenditure that form part of the building blocks for our metering services. Further detail is provided in Attachment 9-1.

9.1 OVERVIEW OF PROPOSED ARR, MAR AND X-FACTORS FOR METERING SERVICES

Table 9–2: Overview of proposed ARR, MAR and revenue X-factors for metering services ($2015, $millions)

	2016	2017	2018	2019	2020	Total	NPV
April 2015 proposal							
Annual Revenue Requirement ('building block' costs)	42.16	31.12	31.62	27.39	25.59	**157.88**	**139.89**
Maximum Allowed Revenue ('smoothed' revenue)	31.17	31.55	31.94	32.33	32.73	**159.71**	**139.89**
X-factors (%)[1]	**58.82%**	**(1.22%)**	**(1.23%)**	**(1.23%)**	**(1.23%)**	**n/a**	**n/a**
Preliminary decision							
Annual Revenue Requirement ('building block' costs)	44.85	43.37	38.26	39.59	38.91	**204.97**	**185.94**
Maximum Allowed Revenue ('smoothed'	43.13	42.06	41.00	39.98	38.98	**205.16**	**185.94**

	2016	2017	2018	2019	2020	Total	NPV
revenue)							
X-factors (%)	**43.01%**	**2.50%**	**2.50%**	**2.50%**	**2.50%**	**n/a**	**n/a**
This submission							
Annual Revenue Requirement ('building block' costs)	38.07	36.86	32.63	33.34	32.35	**173.24**	**146.21**
Maximum Allowed Revenue ('smoothed' revenue)	43.27	31.52	32.13	32.73	33.33	**172.97**	**146.21**
X-factors (%)	**43.01%**	**27.14%**	**(1.91%)**	**(1.89%)**	**(1.81%)**	**n/a**	**n/a**

(1) Positive amount represents a revenue reduction in real terms.

229. Our proposed ARR for metering services for the 2016 regulatory period is $6.32m higher than our April 2015 proposal, reflecting:

- A rate of return that complies with the rate of return objective and provides incentives to invest in our metering services in a manner that promotes the Optimal NEO Position (see Attachment 6-1)
- Higher capital expenditure related to meter hardware and meter installation capital expenditure costs (see Attachment 9-1)
- Higher operating expenditure related to the treatment of our one-off operating expenditure adjustment and the approach to escalating our operating expenditure forecasts (see Attachment 9-1).

230. Our proposed MAR and X-factors for our metering services reflects our intention to pass on the reductions in our costs following the completion of the roll-out of AMI to customers as soon as possible.

9.2 PROPOSED ANNUAL REVENUE REQUIREMENT

231. The ARR represents the amount of revenue we need to generate over the 2016 regulatory period to allow us to invest in, operate and maintain our network efficiently and earn a reasonable return on our investment in providing the metering services our customers value over this period.

232. To calculate our proposed ARR, we used a building block approach.[96] This involved calculating and summing the following building block costs: return on capital (or funding costs); return of capital (depreciation); forecast operating expenditure; forecast tax costs; and other revenue adjustments (see Box 6–1 in our April 2015 proposal).

233. Table 9–3 sets out our revised proposed ARR and building block costs for metering services over the 2016 regulatory period, and compares these to our April 2015 proposal and the preliminary decision. Each of these inputs underlying the proposed ARR is set out in detail in Attachment 9-1.

Table 9–3: Overview of proposed ARR, MAR and X-factors for metering services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
April 2015 proposal						
Return on capital	8.39	6.84	6.00	5.22	4.71	**31.15**

96 Our approach for calculating the ARR is consistent with NER cl. 6.4.3 and the AER's PTRM.

	2016	2017	2018	2019	2020	Total
Return of capital	21.70	12.19	11.85	8.45	6.94	**61.13**
Forecast operating expenditure	10.68	10.97	11.31	11.70	12.07	**56.73**
Tax costs	-	1.12	2.46	2.03	1.86	**7.47**
Other revenue adjustments[1]	1.40	-	-	-	-	**1.40**
Total annual revenue requirement	**42.16**	**31.12**	**31.62**	**27.39**	**25.59**	**157.88**
Preliminary decision						
Return on capital	7.06	6.09	5.17	4.58	3.99	**26.89**
Return of capital	15.72	15.23	10.33	10.79	10.80	**62.87**
Forecast operating expenditure	22.06	22.05	22.05	22.04	22.04	**110.24**
Tax costs	-	-	0.71	2.18	2.09	**4.97**
Total annual revenue requirement	**44.85**	**43.37**	**38.26**	**39.59**	**38.91**	**204.97**
This submission						
Return on capital	10.15	8.77	7.40	6.23	5.13	**37.67**
Return of capital	16.08	15.60	10.68	11.06	10.97	**64.39**
Forecast operating expenditure	11.84	12.49	12.49	12.88	13.25	**62.95**
Tax costs	-	-	2.06	3.17	3.00	**8.23**
Total annual revenue requirement	**38.07**	**36.86**	**32.63**	**33.34**	**32.35**	**173.24**

9.2.1 RETURN ON CAPITAL

234. Our proposed return on capital allowance is the largest of the metering services building block costs, representing around 22% of our total metering services building block costs. We calculated this allowance using three key inputs: our proposed opening value of the asset base; forecast capital expenditure; and proposed rate of return. Each of these inputs is outlined below, and detailed in Appendix 9-1.[97]

9.2.1.1 Proposed opening value of the metering asset base

235. The value of the assets we use in providing regulated metering services is known as the **metering RAB**.[98]

236. Our proposed opening value of the metering RAB is:

- $120.35 higher than our April 2015 proposal, reflecting the difference attributable to the 2014 data where the model uses forecast information rather than actual
- The same as the preliminary decision.

237. More detail on our approach and our populated AER models are provided as Attachment 9-1.

[97] We have calculated our proposed return on capital allowance consistent with NER cl 6.5.2 and the AER's PTRM.

[98] To calculate the opening value of the metering RAB for the 2016 regulatory period, we used an approach consistent with the NER and the AER's metering RAB roll-forward models. This involved taking the opening metering RAB for the 2011 regulatory period, and adjusting this value to take account of our actual and expected capital expenditure over that period, as well as the depreciation of our assets over that period and several other factors (see Box 6–2 in our April 2015 proposal).

9.2.1.2 Forecast capital expenditure

238. Our forecast capital expenditure for metering services over the 2016 regulatory period is set out in Table 9–4.

Table 9–4: Proposed capital expenditure for metering services ($2015, $millions)

Gross capital expenditure	2016	2017	2018	2019	2020	Total
April 2015 proposal	2.41	2.54	2.80	2.94	4.60	**15.29**
Preliminary decision	1.97	2.19	2.31	2.54	5.38	**14.39**
This submission	3.22	2.78	0.87	0.99	3.99	**11.86**

(1) Gross capital expenditure includes equity raising costs.

239. Our proposed forecast capital expenditure for metering services is:

- $3.04m lower than the preliminary decision reflecting that we do not consider the preliminary decision's classification of some capital expenditure, which we consider primarily provides distribution services, to metering capital expenditure will promote the Optimal NEO Position
- $0.91m lower than our April 2015 proposal, reflecting that we have accepted the preliminary decision's positon on elements of our forecast capital expenditure and operating expenditure.

240. More information on this expenditure—including how the proposed capital program represents the efficient level of expenditure required to provide ACS metering services that our customers value—is provided in Attachment 9-1.

9.2.1.3 Proposed rate of return

241. Our proposed rate of return for the 2016 regulatory period is set out in Table 6–2. We calculated this rate of return using an approach consistent with the requirements in the NER.[99]

9.2.2 RETURN OF CAPITAL (DEPRECIATION)

242. We calculated the return of capital allowance using an approach consistent with the NER[100] and the AER's PTRM. The model we used is provided as Attachment 9-X, including our nominated depreciation schedule.

243. Our proposed return of capital allowance is:

- $3.26m higher than our April 2015 proposal
- $1.52m higher than the preliminary decision.

9.2.3 FORECAST OPERATING EXPENDITURE

244. Table 9–5 sets out our proposed forecast operating expenditure for metering services over the 2016 regulatory period and the key assumptions used to forecast this operating expenditure. Attachment 9-1 further details this expenditure, including how it represents the efficient level required to operate and maintain our infrastructure.

99 NER cl. 6.5.2 (b) – (q).

100 NER cl. 6.5.5.

Table 9–5: Key assumptions used to forecast operating expenditure for our metering services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
April 2015 proposal						
Base year operating expenditure	10.29	10.29	10.29	10.29	10.29	**51.43**
Step changes	-	-	-	-	-	**-**
Escalation / rate of change	0.26	0.58	0.93	1.33	1.71	**4.82**
Category specific costs	0.13	0.10	0.09	0.08	0.07	**0.47**
Total forecast operating expenditure	**10.68**	**10.97**	**11.31**	**11.70**	**12.07**	**56.73**
Preliminary decision						
Base year operating expenditure	22.00	22.00	22.00	22.00	22.00	**110.00**
Step changes	-	-	-	-	-	**-**
Escalation / rate of change	-	-	-	-	-	**-**
Category specific costs	0.06	0.05	0.05	0.04	0.03	**0.24**
Total forecast operating expenditure	**22.06**	**22.05**	**22.05**	**22.04**	**22.04**	**110.24**
This submission						
Base year operating expenditure	11.51	11.51	11.51	11.51	11.51	**57.56**
Step changes	-	0.35	-	-	-	**0.35**
Escalation / rate of change	0.27	0.57	0.93	1.32	1.70	**4.81**
Category specific costs	0.06	0.05	0.05	0.04	0.03	**0.24**
Total forecast operating expenditure	**11.84**	**12.49**	**12.49**	**12.88**	**13.25**	**62.95**

9.2.4 TAX COSTS

245. We calculated the tax cost allowance for metering services over the 2016 regulatory period using an approach consistent with the NER[101] and the AER's PTRM.

246. The methods we used to derive these inputs and the values we adopted are set out in Attachment 9–1. Our model is provided as Attachment 9–2.

9.3 PROPOSED MAXIMUM ALLOWED REVENUE FOR METERING SERVICES

247. We 'smoothed' our proposed ARR to derive our proposed MAR for each year of the 2016 regulatory period using an approach consistent with NER requirements and the AER's PTRM. We ensured the MAR is equal to the ARR in net present value terms, subject to minimising the variance between the expected revenue and the ARR in 2020. We calculated the MAR consistent with the NER[102] and the AER's PTRM (our model is provided as Attachment 9–2).

101 NER cl. 6.5.3.

102 NER cl. 6.5.9.

248. Our proposed MAR and X-factors for our metering services (Table 9–6) reflects our intention to pass on the reductions in costs following the completion of the roll-out of AMI to customers as soon as possible.

Table 9–6: Proposed MAR for metering services ($2015, $millions)

	2016	2017	2018	2019	2020	Total	NPV
April 2015 proposal							
ARR (building block costs)	42.16	31.12	31.62	27.39	25.59	**157.88**	**139.89**
MAR ('smoothed' revenue)	31.17	31.55	31.94	32.33	32.73	**159.71**	**139.89**
Preliminary decision							
ARR (building block costs)	44.85	43.37	38.26	39.59	38.91	**204.97**	**185.94**
MAR ('smoothed' revenue)	43.13	42.06	41.00	39.98	38.98	**205.16**	**185.94**
This submission							
ARR (building block costs)	38.07	36.86	32.63	33.34	32.35	**173.24**	**146.21**
MAR ('smoothed' revenue)	43.27	31.52	32.13	32.73	33.33	**172.97**	**146.21**

(1) The NPV is calculated by discounting the ARR and MAR cash flows, using the nominal vanilla WACC.

249. The MAR in the preliminary decision does not promote the Optimal NEO Position given it seeks to recover from JEN's metering customers, costs that relate to the provision of standard control distribution services. This is not optimal because customer who are not JEN metering customers (but are network customers) will get a 'free ride' at the expense of JEN's metering customers, and JEN's metering prices will need to be above the levels would support allocative efficiency.

9.4 PROPOSED X-FACTORS FOR METERING SERVICES

250. Our metering services will be regulated through a revenue cap in the 2016 regulatory period, with the form of control being CPI-X. The X-factors for the 2016 regulatory period need to reflect the change in our revenue (on top of CPI) necessary to allows us to recover our MAR in each year of the period.

251. Our proposed X-factors are shown in Table 9–7. We calculated these X-factors consistent with the NER[103] and the AER's PTRM (our model is provided as Attachment 9–1).

Table 9–7: Proposed X-factors for metering services (%)

	2016	2017	2018	2019	2020
April 2015 proposal (April 2015)	58.82%	(1.22%)	(1.23%)	(1.23%)	(1.23%)
Preliminary decision	43.01%	2.50%	2.50%	2.50%	2.50%
Submission	43.01%	27.14%	(1.91%)	(1.89%)	(1.81%)

252. Our proposed X-factors reflect the lower ARR and MAR we are proposing relative to the preliminary decision. Our submission ensures we can continue to provide safe, reliable and responsive metering network and metering services that our customers value and at the same time, the submission enables us to adapt our services to our changing energy market.

[103] NER cl. 6.5.9.

253. Note that the proposed X-factors do not necessarily determine the actual movements in our individual network tariffs or the actual customer bill outcomes. The price control mechanism for updating the X-factors is provided as Attachment 2-2. Our proposed network tariffs are outlined in our Tariff Structures Statement[104] and the potential customer bill outcomes are shown in Figure OV–1.

[104] JEN, *Tariff structure Statement*, 25 September 2015.

10. OUR FEES AND CHARGES FOR OTHER SERVICES

Table 10–1: Overview of our response to the preliminary decision on our fees and charges for ancillary network services

Our other services	Our response to preliminary decision
Fee-based ancillary network services	≈
Quoted ancillary network services	✓
Public lighting	≈
Negotiating services	✓

Key messages

- Our proposed fees and charges for ancillary network services are largely consistent with the existing pricing of those services. In line with the NER, these prices reflect the costs of providing the relevant service to the customer that requested the service. They were calculated using the approach adopted by the AER for the 2011 regulatory period and the cost allocation methodology approved by the AER. They incorporate:
  - Actual changes in key costs over the 2011 regulatory period and forecast changes in these over the 2016 regulatory period
  - All aspects of the preliminary decision apart from the disallowance of the recovery of tax costs associated with new and temporary connections classified as ancillary network services.
- Our proposed fees and charges for public lighting services incorporates all elements of the preliminary decision in relation to public lighting operation, maintenance, and replacement (**OMR**) services used in the AER's public lighting model except for the rates used for bulk change and repairs per day and traffic management.
- Our proposed negotiating framework incorporates the preliminary decision feedback.

254. While we provide our distribution and metering services to most of our customers, we typically only provide ancillary network and public lighting OMR services to a smaller group of our customers. For this reason, our ancillary network and public lighting OMR services[105] are treated differently. We allocate the costs of providing these services to those that request the services, and set our prices to recover these costs. These costs do not form part of our distribution (see chapter 5) or metering (see chapter 9) services. This ensures that only those customers that benefit from ancillary network services pay for these services.

255. In addition, some of our ancillary network services—such as providing operation, maintenance, repair and replacement of existing public lighting assets on shared electricity metering poles—are provided solely by us in relation to our network areas,[106] while others are provided in more competitive markets:

105 The preliminary decision refers to fee-based services and quoted services collectively as ancillary network services.

106 These are classified as alternative control services, see section 2.1.

- Those services provided solely by us are regulated by the AER through a cap on individual prices of the service (‘fee based service’) or the labour rates used to deliver the service (‘quoted service’). The Victorian metering price reset RIN requires us to set out the direct costs (tasks, labour rates, cost of materials), overheads used in calculating the individual prices and the approach used to determine the costs of providing the quoted services.
- Those services provided in more competitive markets do not require direct regulatory oversight by the AER. The NER require us to allocate our costs in providing these services using our approved cost allocation methodology, and to set out our process for negotiating price or non-price aspects of the service with customers (‘negotiating framework’).[107]

256. This chapter provides an overview of our proposed price changes for our ancillary network services, public lighting and negotiated services. In developing the proposed prices we were guided by the requirements in the NER, the changes occurring in our energy market, and our customers’ priorities and preferences for the 2016 regulatory period. Further detail is provided in Attachments 10-1 to 10-5.

10.1 OVERVIEW OF PROPOSED ANCILLARY NETWORK SERVICES

257. In our April 2015 proposal, we proposed to apply fixed prices for fee based ancillary network services and adopted a bottom-up approach to develop prices for most fee based services. For reserve feeder services the charge was determined on a top-down approach and for quoted ancillary network services, we determined the charge using the labour rates approved by the AER plus material, plant and contractor costs. We proposed to escalate prices over time using a:

- CPI-X price cap for all fee based ancillary network services
- CPI-X price cap on labour rates for quoted ancillary network services, plus material, plant and contractor costs.

258. The preliminary decision did not accept:

- All of our proposed prices for fee based ancillary network services
- Our application of tax recovery to new and temporary connection services[108]
- Our proposed real escalation rate.

259. For those prices not approved, the preliminary decision substituted labour rates, task times and labour escalators the AER considers efficient as inputs into our alternative control services price build-up model[109] and did not include any costs for tax recovery.

260. The preliminary decision accepted JEN’s proposed labour rates for quoted services.[110]

261. Our proposed fees and charges for ancillary network services are largely consistent with the existing pricing of those services and were calculated using the approach adopted by the AER for the 2011 regulatory period and the cost allocation methodology approved by the AER. They incorporate:

107 NER cl. 6.7.5(a).

108 AER, *Preliminary decision, Jemena distribution determination 2016 to 2020, Attachment 16 – Alternative control services*, p 16-17.

109 Ibid, p 16-11.

110 Ibid, p 16-11.

- Actual changes in key costs over the 2011 regulatory period and forecast changes in these over the 2016 regulatory period.
- All aspects of the preliminary decision apart from the disallowance of the recovery of tax costs associated with new and temporary connections classified as ancillary network services.

262. While we do not agree with the preliminary decision's finding that the times taken to perform certain ancillary network services appear excessive given the lack of supporting evidence, we accept the preliminary decision and we have modified the task times modelled in this submission.

263. We do not agree with the disallowance of the recovery of tax costs associated with new and temporary connections classified as ancillary network services given that the resulting prices are unlikely to promote the Optimal NEO Position.

264. We welcome the preliminary decision acceptance of our labour rates for quoted services.

265. Further detail is provided in Attachment 10-1, Attachment 10-3 and Attachment 10-4.

10.2 OVERVIEW OF PROPOSED PUBLIC LIGHTING SERVICES

266. On 3 August 2015, the AER advised that it intends to depart from the classification of all dedicated public lighting services as negotiated services as outlined in final F&A paper. The reclassification means the OMR services for all lights would be classified as an alternative control service in the 2016 regulatory period.

267. On 28 August 2015, JEN proposed charges for OMR services of all lights over the 2016 regulatory period in accordance with the reclassification. The charges were derived by rolling forward the public lighting model for the 2011 regulatory period, and updating inputs and assumptions to reflect changes in working conditions, material costs and labour rates.

268. The preliminary decision did not approve JEN's proposed public lighting charges, as it did not agree with the level of some of our proposed public lighting operating expenditure adjustments resulting from our changes to the inputs and assumptions in the public lighting model. To develop the prices in the preliminary decision, the AER substituted some of the inputs with those rates and costs achieved by other distributors.

269. We do not agree with the preliminary decision on JEN's public lighting charges. When assessing the inputs and assumptions of JEN's public lighting charges in our April 2015 proposal, the preliminary decision has undertaken a simple comparison of costs and performance levels across the Victorian distribution businesses and selected the lowest costs and rates as the substitute for JEN. This approach is overly simplistic as it does not account for the complex contract negotiations covering all the lights.

270. Despite the deficiencies in the preliminary decision approach, JEN accepts all of the substitutions of operating expenditure parameters in the preliminary decision public lighting model, except for:

- Traffic management costs allowed for minor road lights
- Bulk changes and repairs per day for T5 lights.

271. Further detail is provided in Attachment 10-1 and Attachment 10-2.

10.3 OVERVIEW OF PROPOSED NEGOTIATED SERVICES

272. Our April 2015 proposed negotiating framework was largely unchanged from the framework in the 2011 regulatory period, except for some minor adjustments to ensure it covers only services the AER had classified as negotiated distribution services in its final F&A paper.

273. On 3 August 2015, the AER advised that it intends to depart from the classification of all dedicated public lighting services as negotiated services as made in final F&A paper.

274. The preliminary decision required JEN to amend its negotiating framework to refer to Part L of Chapter 6 of the NER rather than Chapter 8 of the NER as it refers to the correct dispute resolution provisions under the NER.[111] Otherwise the preliminary decision accepted JEN's proposed negotiating framework.

275. We welcome the preliminary decision's endorsement and acceptance of our negotiating framework submitted as part of our April 2015 proposal, including the required amendment to the dispute resolution reference to Part L of Chapter 6 of the NER.

276. Further detail is provided in Attachment 10-1. Our proposed negotiating framework is included as Attachment 10-5.

[111] AER, *Preliminary decision, Jemena distribution determination 2016 to 2020, Attachment 17 – Negotiated services and criteria*, October 2015, p 6.