Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review Regulatory Proposal

Revocation and substitution submission

Attachment 7-1 Capital expenditure

Public

6 January 2015

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ABBREVIATIONS

AEMC	Australian Energy Market Commission
APAM	Australia Pacific Airports Melbourne
augex	Augmentation capital expenditure
BAU	Business as usual
CAM	Cost Allocation Methodology
capex	Capital expenditure
CBRM	Condition Based Risk Management
CESS	Capital Expenditure Sharing Scheme
DAPR	Distribution Annual Planning Report
DEDJTR	Development, Jobs, Transport and Resources
ESMS	Electricity Safety Management Scheme
JAM	Jemena Asset Management
JEN	Jemena Electricity Networks (Vic) Ltd
NEM	National Electricity Market
NER	National Electricity Rules
PAS 55	Publicly Available Specification 55 (now ISO 55000)
REFCL	Rapid Earth Fault Current Limiter
repex	Replacement capital expenditure
RIN	Regulatory Information Notice
RIT-D	Regulatory Investment Test-distribution
VCR	Value of Customer Reliability
WSPPB	WSP Parsons Brinkerhoff

OVERVIEW

Key messages

- We welcome many elements of the preliminary decision (**preliminary decision**) on our forecast capital expenditure (**capex**) for the 2016 regulatory period and have sought to address the concerns outlined in the preliminary decision with our April 2015 proposal in this submission.
- We welcome the preliminary decision's recognition that:
  - Our forecasting method for our capital program is generally reasonable
  - Demand forecasts reflect a realistic expectation of demand over the 2016 regulatory period
  - Ageing assets need replacement and that our replacement capex (**repex**) forecast is reasonable
  - Residential and commercial/industrial sector growth represent realistic expectations of connection activity and that our connections and customer contributions forecasts are reasonable
  - Our non-network capex forecast is reasonable.
- Whilst the preliminary decision substituted its own total capex forecast for the 2016 regulatory period, in making its substitute decision it adopted our repex, connections and customer contributions forecasts, and largely our non-network forecast.
- We note that the preliminary decision did not include $29.9m of our customer contributions in our April 2015 proposal associated with special capital works, in our submission we outline why this should be reinstated in the substitute decision. We have also updated our customer contributions to reflect the new National Electricity Rules (**NER**) 5A obligations.
- The preliminary decision substituted our augmentation expenditure (**augex**) forecast with its own due to its concern with three of our proposed projects (the Sunbury and Flemington zone substation upgrades, and the Preston conversion project). The concerns related to the supporting information we provided, the identified need for augmentation, and our consideration of feasible network and non-network options. The AER also asked us to consider whether our Preston conversion project should be categorised as repex rather than augex.
- We have addressed these concerns, amended our augex forecast in this submission for Flemington zone substation upgrade and we have also adjusted our augex and repex forecast to include the Preston conversion project as repex.
- We have also amended our estimate for Melbourne Airport precinct based on the current requirements of our customer and re-categorised the expenditure as connections capex.
- To ensure we only propose allowances for efficient capex we have updated our forecasts with the most recent information. Our revised customer growth is higher resulting overall in increased connection capex forecast for the 2016 regulatory period. Our demand forecasts in this submission are updated with 2014/15 actual data and AEMO's most recent forecast of Victoria's economic outlook data (gross state product) and electricity prices.
- We note that the preliminary decision substituted our capitalised overheads forecast with its own to reflect its lower substituted total capex forecast. We have adopted the method for calculating capitalised overheads from the preliminary decision based on our submission total capex forecast.

1. We have developed our capex forecast for the 2016 regulatory period to be consistent with the NER requirements, and to reflect our customers' stated preference for us to maintain our current safety and service levels. This submission maintains and builds on Jemena Electricity Networks (Vic) Ltd (**JEN**) April 2015

proposal forecast method. The April 2015 proposal (and all supporting evidence and other material contained, or referred to) in it is incorporated into, and forms part of, this submission.

2. The expenditure presented in this attachment is real $2015, unless otherwise stated. Where customer contributions are presented in this chapter—they are inclusive of capitalised overheads as customer contributions are applied to gross connections, including capitalised overheads. Where non-network capital expenditure is presented in this chapter, this is always reported as direct costs as JEN does not apply capitalised overheads to this expenditure category.

3. Forecast capital expenditure presented in this section only (overview) is inclusive of capitalised overheads however, the remaining sections—from section 4 onwards—are presented as direct costs, to provide clarity and to reconcile with the format presented in the preliminary decision.

4. Table OV–1 below summarises our response to the preliminary decision.

Table OV–1: Overview of our submission response to the preliminary decision on forecast capex

Forecast capex category	Preliminary decision	Our response to preliminary decision	Our submission
Forecasting method and key assumptions	Accepted our forecasting method but noted that our key assumptions are not clear	✓	We have clearly set out our key assumptions and identified additional material and demonstrated how it has influenced our forecasts in this submission.
Augex	Did not approve and substituted its own augex forecast to remove three augex projects	✗	We have addressed the concerns outlined in the preliminary decision regarding three major augex projects and maintained the need for these projects in our submission—however with one revision in costs (Flemington) following preliminary design work. We have also re-categorised Preston conversion from augex to repex and the Melbourne Airport precinct project from augex to connections capex.
Connections capex	Accepted our April 2015 proposal as its alternative estimate	≈	We maintain our April 2015 proposal, except for revision to our connections capex forecast to reflect 2014 actual data and updated the driver forecasts for the latest available data (customer numbers and construction industry forecasts). We also revise our estimate for Melbourne Airport precinct connections capex based on updated customer requirements.
Customer contributions	The preliminary decision may have misinterpreted our customer contributions and only approved $102.8m of our proposed $132.65m. The preliminary decision	✗	We maintain the method for calculating customer contributions in our April 2015 proposal, however, updated these for the new NER 5A obligations.

Forecast capex category	Preliminary decision	Our response to preliminary decision	Our submission
	inadvertently did not include $29.9m of customer contributions associated with special capital works (repex)		
Repex	Accepted our April 2015 proposal as its alternative estimate		We maintain our April 2015 proposal, however, re-categorise the Preston conversion project from augex to repex.
Non-network capex	Largely accepted our April 2015 proposal as its alternative estimate		We adopted the position from the preliminary decision and proposed additional expenditure relating to the Power of Choice final rule changes and Regulatory Information Notice (**RIN**) reporting requirements.
Capitalised overheads	Did not approve and substituted its own forecast for capitalised overheads		We adopted the capitalised overheads forecast method outlined in the preliminary decision.
Disposals	Approved with modification to include land disposals		We accepted the approach to include forecast Broadmeadows land sale proceeds outlined in the preliminary decision.

(1) Refer to the overview section of this submission for definitions of the coloured icons used in Table OV–1 to indicate our response to the preliminary decision.

5. Table OV–2 below sets out our April 2015 proposal and submission capex forecast for distribution services compared with the preliminary decision.

Table OV–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.

VARIANCE TO OUR APRIL 2015 PROPOSAL

6. The forecast capex for distribution services shown in Table OV–2 is three percent more than JEN's April 2015 proposal. The key driver of this increase is the $25m (direct costs) of forecast capex to deliver the Australian Energy Market Commission's (**AEMC**'s) Power of Choice program and associated rule changes. This expenditure was not included in the forecast distribution services capex in our April 2015 proposal. However, since submitting our April 2015 proposal the AEMC finalised a number of Power of Choice rule changes that provided us with the necessary certainty to include the forecast capex in this submission.

THE PRELIMINARY DECISION

7. Based on its high level benchmarking metrics, the preliminary decision noted[1] that JEN:

- Performs relatively well on partial factors productivity of capital (ranging from second to fourth best performer in the National Electricity Market (**NEM**) over 2006 to 2013)
- Is the fourth highest performer on multilateral total factor productivity over 2006 to 2013
- Performed well over 2008 to 2012 in terms of capex per customer and capex per maximum demand.

8. The preliminary decision accepted—in the main--JEN's April 2015 proposal forecast capex and found that JEN's forecast:

- Method is generally reasonable
- Capacity growth forecast was reasonable
- Repex, connections, non-network and IT and other expenditure met the capex criteria and represent reasonable estimates
- Demand at the system level, and localised demand forecasts for the relevant augmentation projects, also represent realistic expectations of demand.

9. The preliminary decision's main concern with JEN's April 2015 proposal for forecast capex related to augex:

- The preliminary decision accepted that some of the proposed augmentation projects may be required to alleviate forecast capacity constraints and that JEN's network planning method and criteria reflects good industry practice[2]
- However, the preliminary decision was not satisfied that in each case JEN proposed the most prudent and efficient option to address the need for investment and substituted its own forecast.

10. JEN's submission addresses the preliminary decision's concerns by providing additional information relating to the three augex projects disallowed in the preliminary decision and the Melbourne Airport precinct project which we have now categorised as connections capex.

11. The preliminary decision[3] also raised some concern regarding our approach in assessing non-network options to defer major augmentation capex. JEN's submission addresses these concerns in Attachment 7-16.

12. In addition, the preliminary decision did not include $29.9m (including capitalised overheads) of customer contributions associated with special capital works (categorised as repex) for the relocation of assets as per the Framework and Approach paper[4]. To address a likely misunderstanding of the nature of this forecast expenditure, we resubmit our customer contributions included in our April 2015 proposal (see Attachment 7-2 of this submission) and updated our customer contributions to apply the new NER Chapter 5A method.

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1 AER, *Preliminary decision, Jemena distribution determination 2016 to 2020, Attachment 6 – Capital expenditure* October 2015, section 6.4.4 and pp 6-22 to 6-27

2 Ibid, page 6-43

3 Ibid, page p6-44.

4 AER, *Final framework and approach for the Victorian Electricity Distributors,* 24 October 2014

JEN'S SUBMISSION

13. The forecast capex for distribution services in this submission (shown in Table OV–2) is $89m (including capitalised overheads) or 12% more than the preliminary decision. The main drivers of this increase are:

- $24m (including capitalised overheads) in augex projects for upgrades to Flemington and Sunbury zone substations
- $36m (including capitalised overheads) in repex for the Preston conversion project which we re-categorised from augex
- $19m (including capitalised overheads) in net connections capex relating to changes in customer contributions and projects at Melbourne Airport
- $25m (direct costs) of non-network expenditure for the AEMC's Power of Choice program and associated rule changes.

14. Our submission capex forecast represents the amount necessary to achieve the requirements in the NER,[5] meet our obligations and customers' expectations and promote the Optimal NEO Position.[6]

5 Including the capital expenditure objectives in NER cl 6.5.7.

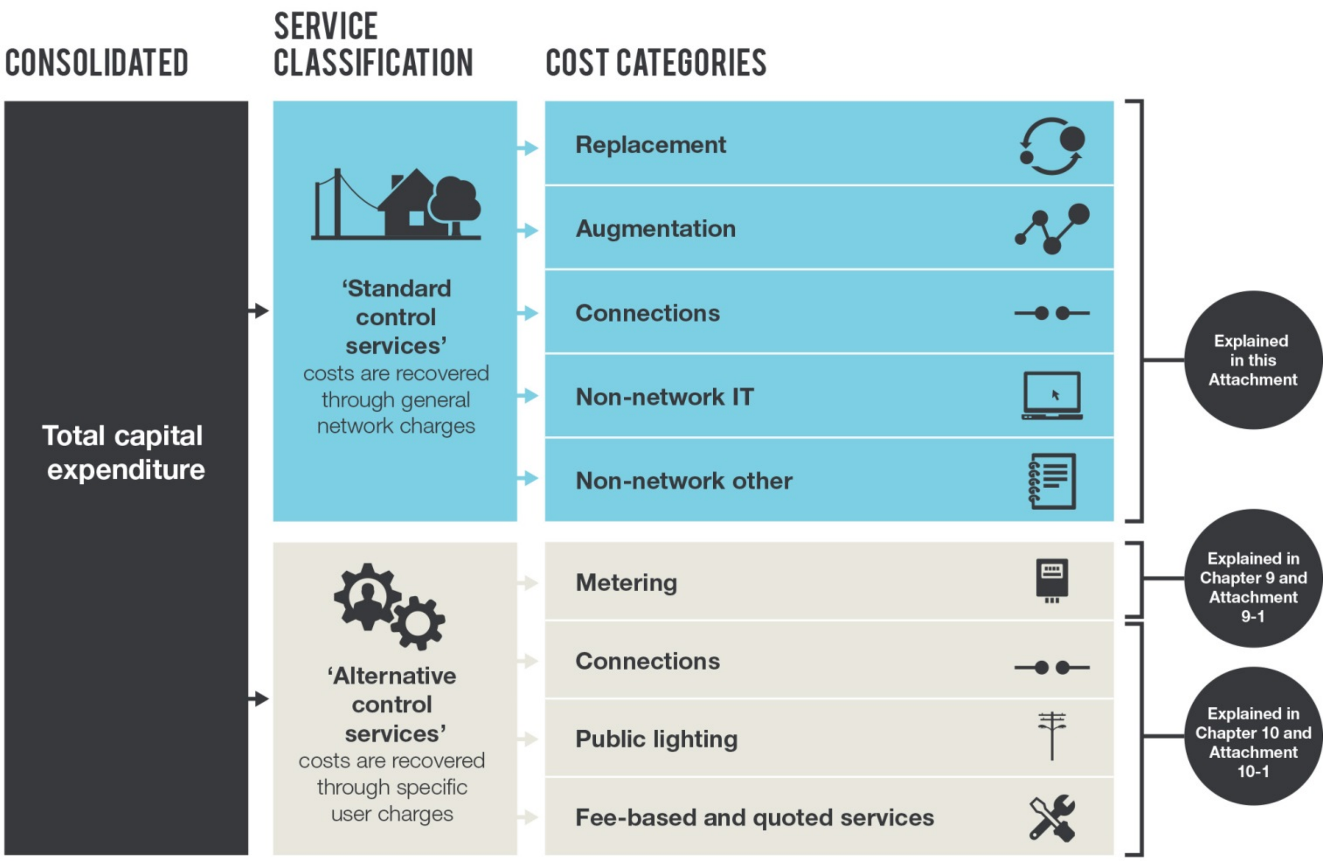
6 The position which contributes to the achievement of the NEO to the greatest degree and best promotes the long term interests of consumers of electricity

1. INTRODUCTION

15. Forecast capex is a key input to the return on and of capital components of our revenue requirement. The NER require[7] that we propose the total capex necessary to provide our distribution services in each year of the 2016 regulatory period, and meet the capex objectives set out in the NER. These objectives include meeting or managing our customers' expected demand, and complying with all relevant regulatory obligations and requirements (including those related to our service levels).[8]

16. Our forecast capex for distribution services includes the capex categories outlined in Figure 1–1

Figure 1–1: JEN's capex categories



17. Our April 2015 proposal provided information about our capex forecast as required by the NER and outlined in AER guidelines,[9] including our capex categories and the approach we have used to develop our capex forecast to ensure it is consistent with the costs that would be incurred by a prudent service provider acting efficiently.[10]

7 NER cl 6.5.7(a).

8 NER cl 6.5.7(a).

9 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.

10 In accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services, NER cl S6.2.2.

18. In developing our capex forecast, we haven take into account anticipated changes occurring in the energy market over the 2016 regulatory period and beyond (see Attachment 7-6 of our April 2015 proposal) and our customers' preferences (see Attachment 4-1 of our April 2015 proposal). We have also considered the concerns raised in the preliminary decision regarding our April 2015 proposal and sought to provide further information to address these in this submission.

19. The following sections of this attachment provide:

- Our forecast capex for distribution services in the 2016 regulatory period by cost category
- Further information on our submission capex forecast as required by the NER and outlined in the AER guidelines, including the difference between this submission forecast, the preliminary decision allowance and our April 2015 proposal capex forecast by cost category.

20. The structure of this attachment is:

- Section 2 sets out JEN's submission capex forecasts for 2016 regulatory period
- Section 3 discusses JEN's key assumptions and forecasting method
- Section 4 sets out JEN's April 2015 proposal for augex forecasts, the preliminary decision and JEN's submission forecast
- Section 5 sets out JEN's April 2015 proposal for connections and customer contributions forecast, the preliminary decision and JEN's submission forecast
- Section 6 sets out JEN's April 2015 proposal for repex forecast, the preliminary decision and JEN's submission forecast
- Section 7 sets out JEN's April 2015 proposal for capitalised overheads forecast, the preliminary decision and JEN's submission forecast
- Section 8 sets out JEN's April 2015 proposal for non-network – IT and other forecast, the preliminary decision and JEN's submission forecast
- Section 9 sets out JEN's submission compliance with the NER.

2. SUBMISSION FORECAST CAPEX

21. Our April 2015 proposal and submission capex forecast for distribution services compared with the preliminary decision allowance is outlined in Table 2–1. Our submission forecast capex represents a prudent and efficient level of total expenditure required to meet our obligations and requirements, maintain existing service levels and to reflect our customers' preferences for the 2016 regulatory period.

Table 2–1: Revised forecast capex 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 however excludes equity raising costs. Equity raising costs are discussed in Attachment 6-1.

22. Table 2–2 sets out our submission proposed capex forecast by cost category.

Table 2–2: Submission capex forecast for distribution services by cost category ($2015, $millions)

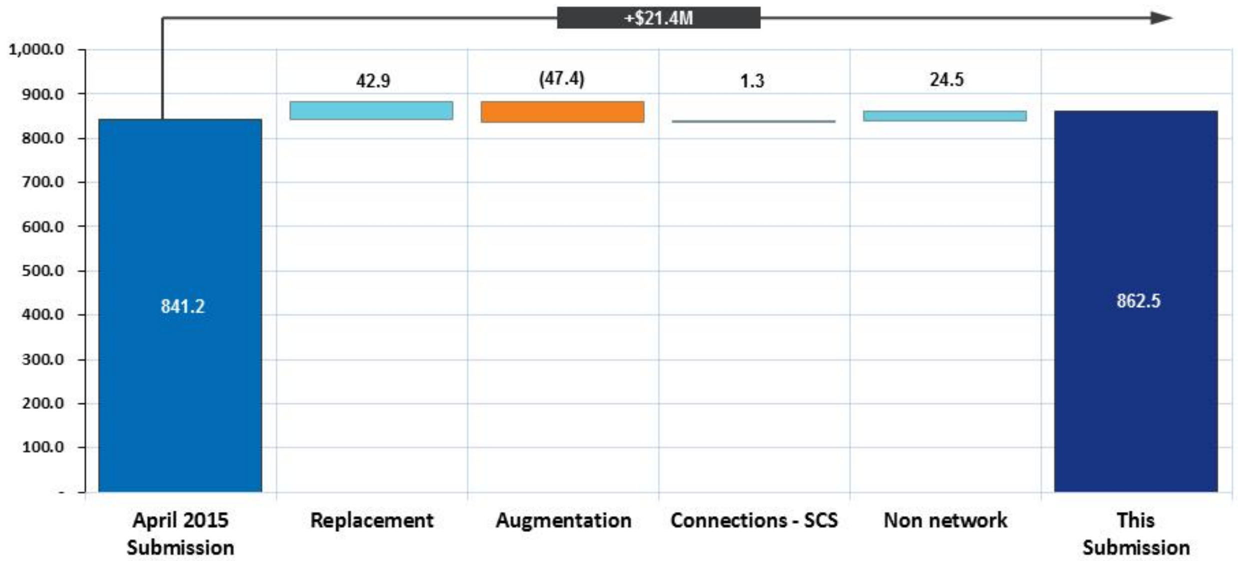
Capex category	2016	2017	2018	2019	2020	Total
Augex	10.66	37.91	27.76	17.86	10.31	**104.49**
Gross connections capex	33.23	41.64	31.93	32.49	32.83	**172.12**
Repex	42.68	48.20	50.25	59.35	55.11	**255.60**
Capitalised overheads	31.94	33.16	33.26	34.71	35.51	**168.58**
Non-network capex	49.24	42.93	26.12	24.08	19.36	**161.74**
Gross distribution services capex	**167.75**	**203.84**	**169.32**	**168.49**	**153.12**	**862.53**
Less customer contributions	29.66	31.88	29.21	30.29	32.20	**153.24**
Less disposals	3.69	0.16	0.17	0.26	0.17	**4.45**
Net services capex	**134.40**	**171.80**	**139.94**	**137.95**	**120.75**	**704.84**

(1) The forecast distribution services expenditure includes a portion of costs that were previously recovered through the AMI Order in Council and includes capitalised overheads but excludes equity raising costs.

23. Our capex forecast for distribution services is included in our updated capex model set out in Attachment 7-2 in this submission.

24. Figure 2–1 below shows the differences between the total capex forecast in our April 2015 proposal and this submission forecast by cost category to arrive at our submission total capex forecast.

Figure 2–1: Forecast capex for distribution services over the 2016 regulatory period by expenditure category ($2015, $millions, includes capitalised overheads) compared with our April 2015 proposal



3. KEY ASSUMPTIONS AND METHODOLOGY

3.1 JEN'S APRIL 2015 PROPOSAL

25. JEN set out key assumptions for its April 2015 proposal capex forecasts in:

- Attachment 8-2 of its April 2015 proposal
- JEN's expenditure forecasting methodology for the 2016-2020 regulatory period, dated 30 May 2014, page 10.[11] The key assumptions include:
  - Spatial peak demand forecasts
  - Customer demand assumptions
  - Embedded generation assumptions
  - Modelling of contingent events
  - Value of customer reliability.

26. JEN's forecasting method is set out in section 7.3 of its April 2015 proposal.

3.2 PRELIMINARY DECISION

The preliminary decision stated that:

- It considers JEN's forecasting method is generally reasonable[12]
- JEN did not include sufficient detail on what assumptions it has relied upon.[13]

3.3 JEN'S RESPONSE AND THIS SUBMISSION

27. In relation to JEN's key assumptions, this submission either provides additional detail and maintains JEN's April 2015 proposal or updates that position as set out below:

- Spatial peak demand forecasts – JEN has revised its position set out in Attachment 3-5 of its April 2015 proposal with its updated demand forecasts set out in Attachments 7-3 to 7-5 of this submission
- Customer growth assumptions – JEN has revised its position set out in Attachment 3-3 of its April 2015 proposal with its updated customer number forecasts set out in Attachments 7-7 to 7-9 of this submission
- Maintains the assumptions within JEN's forecasting method document[14] and our response to AER's queries on this matter.[15]

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11 JEN, *Expenditure forecasting methodology for the 2016-2020 regulatory period,* 30 May 2014.

12 AER, *Preliminary decision Jemena distribution determination – Attachment 6 – Capital expenditure*, October 2015, p 6-21.

13 Ibid, p 6-20.

28. We note that the preliminary decision set lower labour rate and material escalators than proposed by JEN in its April 2015 proposal. JEN has adopted the preliminary decision on escalators in developing its total capex forecast included in this submission (see Attachment 5-1, section 3.3 for more information on our April 2015 proposal, the preliminary decision and our response to AER queries).

[14] JEN, *Expenditure forecasting methodology for the 2016-2020 regulatory period,* 30 May 2014.

[15] JEN, *Electricity Distribution Price Review JEN AER IR#009, Response to AER questions*, 2 July 2015.

4. FORECAST AUGMENTATION EXPENDITURE

29. Table 4–1 below sets out our April 2015 proposal and submission augex forecast for distribution services compared with the preliminary decision allowance.

Table 4–1: 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) Distribution services augex above are reported as 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.

4.1 JEN'S APRIL 2015 PROPOSAL

30. We noted in section 3.3.1 of Attachment 7.3 of our April 2015 proposal that our forecast augex program reflected:

- Similar levels of forecast augex in the 2016 regulatory period, relative to the 2011 regulatory period. Our forecast augex is required to address localised network constraints arising in JEN's growing residential and small business population in three of the Victorian Government's identified metropolitan growth corridors which are forecast to grow above the network average:
  - The Northern growth corridor, encompassing Craigieburn and the Somerton supply region
  - The Sunbury growth corridor, covering the region around Sunbury and Diggers Rest
  - The Western growth corridor, including some of the Western perimeter of our network around Sydenham.
- Slowing growth in maximum demand across JEN but positive overall, with the system-level summer maximum demand forecast (to grow at an average rate of 1.36% per annum) between 2014-15 and 2020-21. This compares to a historical average growth rate of 2.44% per annum over the past nine years.
- Areas within JEN's network where maximum demand is forecast to grow well beyond the network average level (for example, the Northern, Sunbury and Western growth corridors). On the other hand, we are forecasting some parts of the network to experience a decline in maximum demand for a period due to manufacturing closures. As part of our forecast augmentation we analysed these local network conditions to identify and address emerging constraints on the network to ensure we are acting efficiently in meeting our capital expenditure objectives.

4.2 PRELIMINARY DECISION

31. The preliminary decision:

- Was satisfied that JEN's network planning method and criteria reflects good industry practice because JEN applies cost-benefit and probabilistic network planning methods to its augmentation projects that take into account AEMO's Value of Customer Reliability (**VCR**), as is required by JEN's Network Augmentation Planning Criteria[16]
- Accepted that JEN's maximum demand forecasts likely reflect a realistic expectation of demand over the 2016 regulatory period[17] and accepted JEN's demand forecasts at the system level and localised demand forecasts for the relevant augmentation projects[18]
- Accepted that JEN's proposed Craigieburn zone substation augex reflects a prudent and efficient amount for JEN to meet a realistic expectation of demand in JEN's northern growth corridor, and that JEN's decision to build a new substation over demand management for this project is prudent[19]
- Accepted[20] that our proposed forecast capex relating to recommendations subsequently arising from the Victorian Bushfires Royal Commission to install Rapid Earth Fault Current Limiter (**REFCL**) systems within four zone substations, satisfies the capex criteria and is prudent[21]
- Accepted our proposed $5.95m[22] (direct costs) capex to supply growth at and around the Melbourne Airport precinct[23], subject to a cost categorisation issue
- Accepted JEN's proposed $38.6m (direct costs) to augment low and high voltage feeders, and distribution transformers on the basis it reflects a prudent and efficient amount.[24]

32. The preliminary decision was not satisfied that JEN proposed the most prudent and efficient option to address the need for augex investment for each of the issues below.[25]

- For the Sunbury zone substation upgrade, the preliminary decision was not satisfied that JEN's option to rebuild the sub-station at a cost of $9.68 million ($2014, direct costs) as proposed in our April 2015 proposal, is required to meet forecast demand or maintain the reliability of the substation in the 2016 regulatory period. The preliminary decision's alternative capex forecast included $1.32m (direct costs, $2015) for the Sunbury zone substation upgrade[26]
- For the Flemington zone substation upgrade, the preliminary decision was not satisfied that JEN selected the most prudent and efficient option to alleviate capacity constraints in this substation. The preliminary decision's alternative capex forecast included $0.32m (direct costs, $2015) for the Flemington zone substation upgrade[27]

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16 AER, *Preliminary decision Jemena distribution determination* – Attachment 6 – Capital expenditure – October 2015, p 6-43.

17 Ibid, p 6-37.

18 Ibid, p 6-44.

19 Ibid, pp 6-45 to 6-46.

20 Ibid, p 6-86.

21 Ibid, pp 6-55 and 6-90.

22 This represents our proposed augex component of this project (this component is re-categorised as connections capex in this submission), the component proposed as connections capex in our April 2015 proposal was not accepted and is addressed in 5.3.

23 AER, *Preliminary decision Jemena distribution determination* – Attachment 6 – Capital expenditure – October 2015, p 6-36 and 6-51.

24 Ibid, p 6-55.

25 Ibid, p 6-44.

26 Ibid, p 6-45, table 6.9.

27 Ibid, p 6-45, table 6.9.

- The preliminary decision also considered that JEN generally dismisses non-network options to defer major augex. For example, the preliminary decision noted that non-network options such as embedded generation and demand management should be considered to defer capex and JEN had not consistently carried out probabilistic cost benefit analyses to investigate whether these options over the 2016 regulatory period should be pursued
- For JEN's proposed Preston conversion project, the preliminary decision was concerned that JEN did not engage in probabilistic planning as is required by JEN's Network Augmentation Planning Criteria. The preliminary decision noted that JEN provided a value of unserved energy at Coburg South zone substation that is relevant to this project, however did not evaluate the total customer benefit against the cost of proposed work. Instead, JEN's planning approach is largely deterministic and is based on the physical condition of the assets instead of their reliability performance. The preliminary decision indicated that it was difficult to be satisfied that JEN's options and timing for this project are necessary to maintain network reliability, safety or security in the absence of more probabilistic cost benefit assessment. The preliminary decision did not include any capex in its alternative capex forecast for the Preston conversion project[28]
- The preliminary decision also considered that JEN's proposed connections capex associated with a new sub-transmission line to the Melbourne Airport precinct should be categorised as augex—rather than connections capex—however did not provide any allowance for this expenditure as part of JEN's augex requirements.[29]

33. Accordingly, the preliminary decision formed an alternative estimate of the prudent and efficient capex for JEN's total augex requirements for the 2016 regulatory period of $92.4m ($2015, direct costs).

4.3 JEN'S RESPONSE AND THIS SUBMISSION

34. Table 4–2 below summarises our response to the preliminary decision on augex components.

Table 4–2: Overview of our submission response to the preliminary decision on forecast augex

JEN's augex component	Preliminary decision	Our response to preliminary decision	Our submission
Sunbury and Flemington zone substation upgrades and Preston conversion project	Did not include in its substituted total capex forecast	✗	We have prepared additional material addressing the concerns raised in the preliminary decision. We have revised the estimates for the Flemington zone substation upgrade in our submission augex forecast, we maintain our April 2015 proposal forecast for the Sunbury zone substation upgrade and re-categorised the Preston conversion project to repex
Network planning methodology and criteria	Reflects good industry practice but concern as to whether our planning process always results in the most prudent and efficient	≈	We maintain the positon in our April 2015 proposal with some additional material to address the concern in the preliminary decision

28 Ibid, p 6-45, table 6.9.

29 Ibid, p 6-36.

JEN's augex component	Preliminary decision	Our response to preliminary decision	Our submission
	option to address the need for augmentation investment		
Melbourne Airport precinct	Accepted our April proposal to augment the existing sub-transmission loop as its alternative estimate	≈	We have updated our estimate based on the revised customer requirements and re-categorised the expenditure as connections capex (see section 5.3)
Maximum demand forecasts	Represents a realistic expectation of demand	✓	We have updated our maximum demand forecasts utilising the latest information and to align with certain AEMO assumptions used in its September 2015 transmission connection point forecasts
Craigieburn zone substation	Accepted our April 2015 proposal as its alternative estimate	✓	We maintain the positon in our April 2015 proposal
REFCL	Accepted our April 2015 proposal as its alternative estimate	✓	We maintain the positon in our April 2015 proposal
Low and high voltage feeders, and distribution transformers	Accepted our April 2015 proposal as its alternative estimate	✓	We maintain the positon in our April 2015 proposal

35. The preliminary decision on its alternative augex forecast does not achieve the **Optimal NEO Position**[30] because:

- It does not enable JEN to recover its prudent and efficient costs in providing its distribution services and meeting its regulatory obligations
- Under investing in the Sunbury and Flemington zone substation upgrades and the Preston conversion project will result in unreliable supply to the detriment of consumers over the 2016 regulatory period. Further, not investing in the Preston conversion project will increase safety risks to personnel and may create permanent damage to conductors and joints (see section 3 of Attachment 7-15 of this submission).

36. JEN disagrees with the preliminary decision to disallow the Sunbury zone substation upgrade, the Flemington zone substation upgrade and the Preston conversion Project. JEN has set out new material to address the concerns raised in the preliminary decision on these three augex projects.

37. JEN maintains the position set out in its April 2015 proposal for the following matters:

- JEN's network planning methodology and criteria[31] outlined in our DAPR[32]

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30 The position which contributes to the achievement of the National Electricity Objective (**NEO**) to the greatest degree and best promotes the long term interests of consumers of electricity

31 Submitted as supporting information with JEN's response to the EDPR RIN—see JEN PR 007 Network augmentation planning criteria

32 Submitted as supporting information with JEN's response to the EDPR RIN—see ELE PL 0037 2014 Distribution Annual Planning Report Rev2.0. JEN has since published its 2015 DAPR on its website, available at: http://jemena.com.au/getattachment/industry/electricity/Network-planning/2015-Distribution-Annual-Planning-Report.pdf.aspx

- Augex to develop a new zone substation at Craigieburn[33]
- Forecast capex of $6.2m (direct costs) related to recommendations arising from the Victorian Bushfires Royal Commission to install REFCL technology to assist mitigate bushfire ignition risk[34]
- Forecast capex of $38.6m (direct costs) to augment low and high voltage feeders, and distribution transformers on the basis it reflects a prudent and efficient amount.[35]

38. JEN's submission provides additional material for the following matters:

- Upgrade of Sunbury zone substation (see section 4.4.1 and Attachments 7-11 and 7-12)
- Upgrade of Flemington zone substation (see section 4.4.2 and Attachments 7-13 and 7-14)
- Preston conversion project (see section 4.4.3 below and Attachment 7-15). Further, JEN has considered the observations made in the preliminary decision that this project includes a number of repex drivers and have re-categorised the project as repex. JEN maintains that the primary drivers of this project in 2008 (when the project was initiated) were primarily related to capacity and asset condition and accordingly we maintain that categorising the project originally as augex is appropriate—particularly considering that the replacement components were not like-for-like replacements.

  Considering the progression of the project since then, we agree that there are repex drivers influencing the stages of the project within the 2016 regulatory period. Given these changes over time, JEN has re-categorised the Preston conversion project as repex in this submission to acknowledge the current primary drivers of the project.

39. Further detail on JEN's response to the preliminary decision on these projects is outlined in section 4.4.

4.3.1 MAXIMUM DEMAND FORECAST

40. We welcome the preliminary decision that our maximum demand forecasts likely reflect a realistic expectation of demand over the 2016 regulatory period. To ensure we only propose allowances for efficient capex we have updated our maximum demand forecasts to reflect new information and model inputs (for example, Gross State Product and electricity pricing) consistent with the approach taken by the Australian Energy Market Operator (**AEMO**) in its September 2015 transmission connection point forecasts (see Attachment 7-4 for more discussion).

4.3.2 JEN'S WORLD CLASS GOVERNANCE

41. We do not agree with the concern raised in the preliminary decision that JEN's planning processes do not appear to always result in the most prudent and efficient option to address the need for augmentation investment.[36] We disagree with those reasons because we apply a robust, economic approach to assessing net market benefits with augmentation works—which was noted in the preliminary decision—and is supported by our **PAS 55**[37] accredited governance framework.

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[33] See Attachment 7-3 of our April 2015 proposal

[34] See Attachment 7-3 of our April 2015 proposal and JEN, *Jemena Electricity Networks, Bushfire Mitigation Plan, 2015-2020, Document No. JEN PL 0100*, 7 September 2015

[35] See Attachment 7-3 of our April 2015 proposal

[36] Ibid, p 6-9.

[37] Publicly Available Specification 55 (now ISO 55000)

4.3.3 JEN'S CONSIDERATION OF NON-NETWORK OPTIONS

42. We do not agree with the assertion that we generally dismiss non-network options to defer major augex and that we have not consistently carried out probabilistic cost benefit analyses to investigate the benefit of non-network options over the 2016 regulatory period[38]. To support these views, JEN engaged Advisian to undertake an independent external review of our approach of assessing non-network alternatives and tested it against all 35 augex projects included in our augex forecast. Advisian found that JEN's approach is logical and consistent with the practices of other distribution network service providers (see Attachment 7-16 for more detail).

43. Advisian's review identified four augex projects which passed the initial screening and might be possibly substituted with non-network alternatives. These four projects were then assessed with economic cost benefit analysis and include two zone substation projects (Sunbury and Flemington) and two high-voltage feeder projects (Heidelberg, HB-21 and Essendon, ES-23).

- With regard to the two zone substation projects, energy efficiency and demand response were found to have net market benefits comparable to the recommended network option. However, the significant demand reduction required (which is in the order of half the total maximum demand forecast) cannot be achieved in practice due to the large number of customers that would be required to achieve the required demand reduction[39]. Even if this approach were technically feasible, the cost to aggregate such a large volume of customers will exceed the economic benefit. Nonetheless, JEN has initiated Regulatory Investment Test-Distribution (**RIT-D**) consultation and assessment processes for these two projects with responses due by 29 January 2016.
- With regard to the two high-voltage feeder projects, demand response options were shown to have net market benefits comparable to the two network augmentation options based on the assumption that the customer base is made up of commercial and industrial loads. This, however, is not the case, the customer base on these feeders is mostly residential and therefore JEN considers that sufficient demand reductions with the same cost assumptions—as outlined in the Advisian report—cannot be achieved.

44. JEN notes that a number of its forecast augmentation projects will meet the RIT-D trigger threshold under clause 5.17 of the NER and undergo the RIT-D consultation and assessment process. Identifying which projects within the planning cycle investment horizon are required to undergo the RIT-D consultation and assessment is a business-as-usual step in our annual planning cycle.

45. Our 2014 Distribution Annual Planning Report (**DAPR**) identified that no RIT-D consultations were undertaken during that year. However, on 23 October 2015, we published non-network options reports for the Flemington zone substation upgrade and Sunbury zone substation upgrade projects on our website[40], and are seeking submissions by 29 January 2016. JEN also notified providers of non-network solutions registered on our demand-side engagement register.

4.3.4 MELBOURNE AIRPORT PRECINCT PROJECT

46. JEN notes that it included the preliminary decision approved $5.95m (direct costs) for Melbourne Airport precinct as part of its augex forecast (part of 'other projects') to augment (split) the existing transmission loop, rather than as part of its connections capex forecast in its April 2015 proposal, as implied in the preliminary

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38 AER, *Preliminary decision Jemena distribution determination* – Attachment 6 – Capital expenditure – October 2015, p 6-44.

39 Analysis of the commercial and industrial customers supplied by FT zone substation reveals that the top 11 customers only have 14 MVA of demand in total, compared to the 22 MVA load reduction required by 2021. Similarly, our preliminary assessment of commercial and industrial customers in the Sunbury area reveals that the top twenty-four customers account for only 10 MVA of demand, compared to the 25 MVA of load reduction required by 2021.

40 https://jemena.com.au/industry/electricity/network-planning

decision[41]. JEN has reassessed the needs of the Melbourne Airport precinct project and has updated its capex forecast and re-categorised the expenditure as connections capex (see section 5.3).

4.3.5 JEN'S SUBMISSION AUGEX FORECAST

47. JEN's submission augex forecast for the 2016 regulatory period is $104.5m (direct costs) which is necessary to achieving the Optimal NEO Position because:

- It will enable JEN to recover its prudent and efficient costs in providing its distribution services and meeting its regulatory obligations
- It incentivises JEN to efficiently invest in its network
- JEN will be able to maintain the quality and reliability of supply to its consumers
- We have thoroughly assessed how best to prudently deliver our proposed capex 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 requirements in the NER, efficiently meet our obligations and customers' stated expectations, and promote the long-term interests of our consumers.

4.4 SUBSTITUTED AUGMENTATION PROJECTS

48. This section sets out additional material relating to the Sunbury and Flemington zone substation upgrades, and the Preston conversion project (collectively the three augex projects) to deal with the concerns raised in the preliminary decision.

49. For the three augex projects, JEN engaged WSP Parsons Brinkerhoff (**WSPPB**) to provide an independent view of the:

- Drivers of the projects and their implications
- Viable technical options to address the drivers and needs, including non-network options
- Reasons for the rejection of non-viable options
- Cost benefit analysis of viable options, and
- Preferred option.

50. WSPPB's independent views on the above—and JEN's response to the concerns in its preliminary decision—are set out below for the three augex projects.

4.4.1 UPGRADE SUNBURY ZONE SUBSTATION

51. JEN has set out the background to the Sunbury zone substation upgrade in Attachment 7-3 of its April 2015 proposal. JEN wishes to revise its position set out in its April 2015 proposal, with the material set out below and in Attachments 7-11 and 7-12 of this submission.

[41] AER, *Preliminary decision Jemena distribution determination* – Attachment 6 – Capital expenditure – October 2015, p 6-47.

4.4.1.1 Preliminary decision

52. The preliminary decision disallowed $10.9m (direct costs, $2015) to redevelop the Sunbury zone substation and replace existing assets. The activities within this project scope include establishing a new control building and replacing the existing outdoor 22 kV switchyard with indoor 22 kV switching. The preliminary decision identified age, condition of some assets and reliability concerns as the primary drivers (ie. not capacity constraints) and the project was disallowed on this basis. The preliminary decision was not satisfied that this capex is necessary to maintain network reliability, security or safety in accordance with the capex objectives of the NER.[42] The preliminary decision only included $1.32m (direct costs, $2015) in its alternative capex forecast to increase capacity with a new transformer.

53. In reaching its conclusion, the preliminary decision stated:

> *"If Jemena is of the view that, given the condition of the assets, it requires more than business as usual repex to meet the capex objectives, then it should provide supporting information to this effect in its revised proposal (including updating any historical and forecast expenditure of this type in the form of an updated response to RIN template 2.2, and other supporting material such as business cases, options analysis and cost benefit analysis).*[43]

4.4.1.2 JEN's response and this submission

54. JEN does not agree with the preliminary decision to exclude much of the expenditure required to upgrade the Sunbury zone substation from its alternative capex forecast.

55. In response to the preliminary decision, we note that:

- We have considered the comments in the preliminary decision which suggest that only a small proportion of proposed capex was allowed for this project on the basis that the remaining capex (to build the new substation) is primarily driven by age condition and some reliability concerns—for which we have not provided sufficient information on these drivers.
- We agree that asset condition and supply reliability are significant drivers to redevelop Sunbury zone substation, however these drivers are not exclusively limited to repex projects. In this case, and with other augex projects, it is the capacity constraints that determines the timing of the project, which in turn leads JEN to maintain treating the project as augex. As the timing constraint requires capacity be upgraded by 2018, and our condition based risk management assessments indicate that the asset must be replaced by 2020, we categorise the project as augex.
- We have submitted an addendum to the Network Development Strategy (see Attachment 7-12 of this submission) associated with this project to more clearly articulate the point above and how the timing of the capacity, reliability and asset condition drivers can influence how we categorise the project internally.
- We have resubmitted the market net benefit analysis after expanding the analysis to better reveal the full range of options we considered, including assessing staged-timing options and quantifying the impact of asset condition on customer reliability.
- Our market benefit analysis indicates that the greatest benefit will be realised by replacing the 10MVA transformer with a new 20/33MVA and undertaking segmentation works on both the 66kV and 22kV (Option 4E in JEN's Addendum to the Sunbury Network Development Strategy—see Attachment 7-12). This option has a net market benefit of $589.06 million consisting of $9.9 million (direct un-escalated $2015) augmentation costs.

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42 AER, *Preliminary decision Jemena distribution determination* – Attachment 6 – Capital expenditure – October 2015, p 6-47.

43 Ibid, p 6-49.

- The market benefits that are forecast to be delivered by the preferred solution are predominately driven by a reduction in the amount of expected unserved energy over the assessment period. These market benefit assessments assist JEN to maintain the most optimal mix of network reliability, security, safety and quality of supply in the Sunbury supply area and therefore satisfy the capex objectives.
- On 23 October 2015, JEN published a non-network options report for the Sunbury zone substation upgrade project on its website[44] with a call for submissions by 29 January 2016. JEN also notified providers of non-network solutions registered on our demand-side engagement register. Early discussions with at least one key provider of non-network alternatives have indicated that we do not expect any viable non-network alternatives exist for this project.

56. Following its independent review of the Sunbury zone substation upgrade, WSPPB[45] concluded that:

- JEN did not include the impact of asset condition and the switching arrangements on the assessment of customer reliability. These drivers should be incorporated into the assessment identifying the preferred option.
- The options presented by JEN were correctly structured to address capacity constraints from 2018 based on JEN's ten-year demand forecast. However, the suite of options did not consider any staged works that (i) address the capacity constraint now, and (ii) have the flexibility to mitigate the impact of asset condition reliability as the demand on the substation increases over time.

57. In its assessment of the Sunbury zone substation upgrade and the preliminary decision, WSPPB considered 12 options to address the key drivers over the 2016 regulatory period. WSPPB identified further sub-options[46] to address the segmentation solutions to the reliability driver. These are provided in Attachment 7-11 to this submission.

58. Of the available options, WSPPB rejected all except the following:

- Option 1 - Do-Nothing (BAU)
- Option 2D - Upgrade TX2 with protection in situ, 66kV and 22kV segmentation
- Option 4A - Upgrade TX2 with new protection in new control room
- Option 4D - Upgrade TX2 with new protection in new control room, 66kV segmentation and 22kV segmentation (partly indoor)
- Option 4E - Upgrade TX2 with new protection in new control room, 66kV segmentation and 22kV segmentation (indoor).

59. The majority of options rejected by WSPPB were due to the following reasons:

- The option derived a very low net market benefit
- The option was already implemented with no further benefits to be realised.

60. WSPPB's market benefit analysis of the options concludes that the greatest benefits are realised by replacing the 10MVA transformer with a new 20/33MVA and undertaking segmentation works on both the 66kV and 22kV (Option 4E). This option has a net present value of $589.06 million consisting of $9.9 million (direct un-escalated $2015) augmentation costs and supports our recommended option in the April 2015 proposal. The customer

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[44] https://jemena.com.au/industry/electricity/network-planning

[45] Attachment 7-11 WSP | Parsons Brinckerhoff, *Sunbury project, independent assessment, December 2015,* Executive summary

[46] Attachment 7-11 WSP | Parsons Brinckerhoff, *Sunbury project, independent assessment, Table 4.1, December 2015,* p8

benefit in terms of avoided cost of expected unserved energy greatly exceeds the net cost of the preferred option showing that the works should be undertaken to realise the maximum benefits.[47]

61. Therefore, JEN's augex forecast in this submission includes $9.9m (direct costs) to upgrade Sunbury zone substation, the same amount in JEN's April 2015 proposal.

4.4.2 UPGRADE FLEMINGTON ZONE SUBSTATION

62. We set out the background to the Flemington zone substation upgrade in Attachment 7-3 of our April 2015 proposal. We have revised our position set out in our April 2015 proposal with the material below and in Attachments 7-13 and 7-14 of this submission.

4.4.2.1 Preliminary decision

63. The preliminary decision disallowed $7.9m (direct cost, $2015) to upgrade the Flemington zone substation and instead only included $0.32m (direct cost, $2015) in its alternative capex forecast, this amount is for the unit cost of new 11 kV transformer cables which it deemed to be the primary capacity constraint within the zone substation. Whilst the preliminary decision recognised that the assets in this zone substation will reach the end of their life within the next ten years, it was not satisfied that replacement is necessary in the 2016 regulatory period to maintain network reliability, safety or security.[48] Further, the preliminary decision was not satisfied that JEN has selected the most prudent and efficient option to alleviate capacity constraints in this substation.[49]

64. In coming to this positon the preliminary decision stated:

> *"If Jemena considers that these assets need to be replaced within the 2016–20 period, it should submit more detailed information about the existing reliability performance of these assets and quantify the costs to consumers from any expected reliability deterioration (or alternatively provide information about why this capex cannot be considered within our repex allowance if necessary)."*[50]

4.4.2.2 JEN's response and this submission

65. JEN does not agree with the preliminary decision to exclude the Flemington zone substation upgrade from its alternative capex forecast.

66. In response to the preliminary decision, JEN notes:

- The preliminary decision's alternative augex forecast for Flemington zone substation of $0.32m ($2015, direct costs) was based on JEN's response to AER questions stating "the forecast cost to replace the two 11 kV transformer cables is $322k".[51] However, the estimate provided to the question did not include any project setup costs, labour, implementation, construction management etc. and therefore materially understates the full cost of actually replacing the two 11 kV transformer cables. The full cost to conduct this option as a stand-alone project is $0.92m ($2015, direct costs).

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47 Ibid, s 4.2.3

48 AER, *Preliminary decision Jemena distribution determination – Attachment 6 – Capital expenditure – October 2015*, pp 6-49 to 6-51.

49 Ibid, p 6-44.

50 Ibid, p 6-51.

51 JEN, *Electricity Distribution Price Review JEN AER IR#16.1, Response to AER questions*, 19 August 2015.

- JEN's project estimate submitted with our April 2015 proposal was based on our expectation at the time that replacing transformer cables in the existing ducts was not possible as JEN expected that the higher capacity cables required to meet the existing and forecast demand would not fit within the existing ducts. JEN's standard for 11 kV cables connecting 30 MVA transformers is three single core 630mm copper cables per phase per transformer installed in conduits with a minimum diameter of 150mm. The Flemington zone substation was built with only two ducts per phase per transformer, and uses 100mm diameter conduits. To obtain the required ratings a third duct per phase per transformer would be required. Obtaining additional ducts would require significant civil excavation works throughout the concrete slab floor (ie. building foundations).

- Preliminary design works have occurred since submitting our April 2015 proposal which suggest that it may be possible to utilise the existing cable ducts with higher rated cables, thereby removing the need to build a new control building. JEN's revised network development strategy—updated to reflect the new information that has come to light since undertaking preliminary engineering works—presents a revised cost estimate for this project (see Attachment 7-14).

- JEN notes the reference in the preliminary decision to a project conducted by ActewAGL Distribution at Belconnen[52] zone substation in 2013 to upgrade the emergency capacity at the substation. JEN also notes the implied parallels drawn between this project and the Flemington upgrade and the assertion that the projects are sufficiently similar to warrant overlaying the Belconnen design—and therefore substituting the lower cost assumptions—to JEN's Flemington upgrade project.

  As noted above, JEN has recently undertaken detailed design engineering at Flemington zone substation since our April 2015 proposal which has provided us enough confidence that the transformer cables can be upgraded and replaced within the existing cable ducts. However, we maintain that this alone does not address the capacity constraint at Flemington zone substation because of the capacity constraint of the existing 11kV switchboards.

- JEN considers that the preliminary decision's alternative capex forecast for the Flemington zone substation is not representative of the required costs as it does not address the risks arising from declining reliability resulting from aged assets and safety and therefore does not represent a viable technical solution. See Attachment 7-14, table ES-1 where JEN present our economic cost benefit analysis indicating that the option to replace only the transformer cables does not maximise the net present value of the net market benefits.

- The Flemington zone substation upgrade project was one of two projects that qualified to undergo the RIT-D consultation and assessment process. On 23 October 2015, JEN published a non-network options report on its website[53] calling for responses by 29 January 2016. JEN also notified providers of non-network solutions registered on our demand-side engagement register.

67. In its review of the Flemington zone substation upgrade, WSPPB[54] concluded that:

- JEN has not comprehensively conveyed the key drivers in its documentation submitted with the April 2015 proposal. WSPPB also found that the fundamental driver for the Flemington zone substation upgrade is insufficient capacity to meet existing and increasing demand. Declining reliability resulting from aged assets and safety are not primary drivers for augmentation, but may influence the analysis and selection of the most prudent and therefore preferred option. When both insufficient capacity and declining reliability are taken into consideration the energy at risk under the current conditions is considerable.

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52 AER, *Preliminary decision Jemena distribution determination – Attachment 6 – Capital expenditure*, October 2015, p 6-50 to 6-51

53 https://jemena.com.au/industry/electricity/network-planning

54 Attachment 7-13 WSP | Parsons Brinckerhoff, *Flemington zone substation, independent assessment of supply capacity limitations*, December 2015, Executive summary.

- The options considered by JEN in its April 2015 proposal do not encompass all viable technical solutions or the optimal timing of options. Therefore, JEN may not have selected the most prudent option.
- The greatest benefit will be realised by replacing the transformer cables and the 11 kV switchboards in the existing building.

68. In its assessment of the Flemington zone substation upgrade and the preliminary decision, WSPPB considered 10 options (including sub-options)[55] to address the key drivers over the 2016 regulatory period.

69. Based on WSPPB's sensitivity analysis, option 4b has a consistently high NPV out of all options and is therefore the preferred option.[56]

70. Therefore, JEN's augex forecast in this submission includes $5.5m—reduced from $8.2m (both in direct costs) in JEN's April 2015 proposal—to upgrade Flemington zone substation by replacing the transformer cables and the 11 kV switchboards in the existing building.

4.4.3 PRESTON CONVERSION PROJECT

71. JEN has set out the background to the Preston conversion project in Attachment 7-3 of its April 2015 proposal. JEN wishes to revise its position set out in its April 2015 proposal, with the material set out below and in Attachment 7-15 of this submission.

4.4.3.1 Preliminary decision

72. The preliminary decision disallowed $27.5m ($2015, direct cost) for the Preston conversion project on the basis that it was not satisfied by the stated need to expand the capacity of the network. Further, the preliminary decision stated it is not clear that JEN would have proposed this project if it were not for its assessment of the condition of the relevant assets.[57]

73. Finally, the preliminary decision noted that JEN had not engaged in probabilistic planning in its assessment of this project and had dismissed other potential prudent lower cost options that will alleviate capacity concerns.[58]

4.4.3.2 JEN's response and this submission

74. JEN does not agree with the preliminary decision to exclude the Preston conversion project from its alternative capex forecast.

75. In its review of the Preston conversion project, WSPPB noted that:

- The key driver for the projects over the 2016 regulatory period is the need to replace assets that are in poor condition
- Secondary drivers include:
  - The forecast capacity constraints on the 22kV Coburg-South zone sub-station

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55 Attachment 7-13 WSP | Parsons Brinckerhoff, *Flemington zone substation, independent assessment of supply capacity limitations*, December 2015, pp10-11

56 Ibid, section 4.2.3.

57 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 6 – Capital expenditure October 2015*, p 6-53.

58 Ibid, pp 6-44 and 6-54.

- The lack of transfer capability to cover for single contingency feeder outages, created by the conversion program undertaken to date.

- New customers in the 6.6kV areas may not be connected until a conversion to 22kV is undertaken
- The logical conclusion is to develop replacement options that also consider the future augmentation requirements. This is the approach taken by JEN.[59]

76. In reviewing JEN's choice of solutions WSPPB[60] concluded that:

- JEN has appropriately considered the key drivers but has not considered all viable options or determined the optimal timing of options.
- The options presented by JEN were structured to address the issues caused by assets in poor condition—particularly at Preston and East Preston zone substations. They also address capacity constraints on the 6.6kV network that prevents further load from being connected at an efficient cost. However, the suite of options did not consider non-standard substation designs that might have reduced the overall scope of the required works.

77. In its assessment of the Preston conversion project and the preliminary decision, WSPPB considered the following options address the key drivers over the 2016 regulatory period:

- Option 1: Do nothing
- Option 2: Replace the 6.6kV distribution assets
- Option 3: Convert the 6.6kV network to 22kV using standard design substations
- Option 4: Convert the 6.6kV network to 22kV using non-standard design substations
- Option 5: Convert the 6.6kV network to 22kV using standard design substations, with load transfers.

78. Based on WSPPB's NPV analysis of the viable options, option 3 has the most favourable NPV and the lowest cost[61]—this finding supports JEN's recommended option. WSPPB developed augmentation options that also consider the whole of life costs of future replacements and the potential impact of asset failures. WSPPB's analysis shows that substantial load is at risk (currently valued at $39.8m and rising to $69.7m by 2022), which far exceeds the cost of the all five options identified above at approximately $35m, therefore, the program should continue as scheduled. This analysis responds to concerns noted in the preliminary decision that the planning approach JEN appears to have applied to the Preston Conversion project is largely deterministic and based on the physical condition of the assets instead of the reliability performance of the assets.

79. Based on WSPPB's review,[62] and in response to the preliminary decision[63] JEN has treated the Preston conversion project as repex in this submission rather than augex for the following reasons:

- WSPPB agrees with the preliminary decision that the current key driver for the timing of the expenditures proposed for the 2016 regulatory period is replacement of assets in poor condition. This is different to the original driver when the project was initiated in 2008, which was driven by augmentation requirements.

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59 Attachment 7-15 WSP | Parsons Brinckerhoff, *Preston augex project, review and response to the preliminary decision*, December 2015, section 3.1.

60 Ibid, executive summary and s 4.1.

61 Ibid, s 4.2.2.

62 Ibid, s 4.3.

63 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 6 – Capital expenditure,* October 2015, p 6-53.

- However, WSPPB notes that a like for like replacement is not a viable replacement option and that a non-like for like replacement option is required to address forecast capacity constraints. The cost of the replacement assets at 22kV will be higher than assets at 6.6kV, but will provide the future required capacity at a lower cost. Overall, the total cost is minimised, meeting the requirements of the NER capex objectives.

80. Given JEN has re-categorised Preston conversion expenditure as repex, JEN conducted repex predictive modelling including this project (for historical expenditure and that forecast over the 2016 regulatory period). JEN submits a recalibrated repex forecast using the AER's repex predictive modelling approach at Attachment 7-10 and explains this process in section 6.3.1.

81. Following the WSPPB independent review and JEN opting to categorise expenditure associated with Preston conversion over the 2016 regulatory period as repex, JEN is still submitting the same forecast capex and recommended option in this submission as we proposed in our April 2015 proposal. This option—converting the 6.6 kV network to 22 kV using standard design substations—maximises the net present benefit to our customers and relative to other options, including do nothing, represents the Optimal NEO Position. See our addendum to the Preston area network development strategy at Attachment 7-20 and WSPPB's independent report at Attachment 7-15 for further information.

5. FORECAST CONNECTIONS & CUSTOMER CONTIBUTIONS CAPEX

82. Table 5–1 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 5–1: 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 contribution capex in Table 5–1 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.

83. Table 5–2 below sets out our April 2015 proposal and submission connections capex for distribution services compared with the preliminary decision. This reveals the change in connections arising from updating our customer number forecasts (see Attachments 7-7, 7-8 and 7-9) and categorising some expenditure relating to the Melbourne Airport precinct project as connections capex that was categorised as augex in our April 2015 proposal (see Table 5–4).

Table 5–2: Forecast connection capex for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
April 2015 proposal	32.79	34.61	37.19	32.66	33.73	**170.97**
Preliminary decision	31.90	31.10	30.50	32.70	33.70	**159.90**
This submission	**33.23**	**41.64**	**31.93**	**32.49**	**32.83**	**172.12**

(1) Distribution services connections capex in Table 5–2 above are direct costs (excluding capitalised overheads)

84. Table 5–3 sets out our April 2015 proposal and submission forecast customer contributions capex for distribution services compared with the preliminary decision.

Table 5–3: Forecast customer contributions capex for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
April 2015 proposal	26.45	25.58	27.34	25.70	27.59	**132.65**
Preliminary decision	20.40	19.90	21.60	19.70	21.20	**102.80**
This submission	**29.66**	**31.88**	**29.21**	**30.29**	**32.20**	**153.24**

(1) Distribution services customer contributions capex in Table 5–3 above include capitalised overheads.

85. The change in contributions between the preliminary decision and this submission are derived by four key factors:

1. Special capital works customer contributions that JEN expect were omitted in the preliminary decision
2. Changes in our customer mix arising from updated customer number forecasts (ie. lower forecast connections forecast for business supply>10kVA and higher forecast connections for medium density housing and dual and multiple occupancy)
3. Categorising some expenditure relating to the Melbourne Airport precinct project as connections capex that was previously augex
4. Changes in customer contributions arising from the transition from Guideline 14 to NER chapter 5A.

5.1 JEN'S APRIL 2015 PROPOSAL

86. As noted in section 3.2.1 of attachment 7-3 of our April 2015 proposal our connections expenditure is driven largely by growth in customer numbers. Over the 2016 regulatory period, our customer numbers are forecast to grow 0.58% annually (see Attachment 7-7 of this submission). Some of the projects identified by our customers as connection activities over the 2016 regulatory period include:

- Expanding the commercial precinct in and around Melbourne Airport
- Redeveloping the decommissioned paper mill site in Fairfield with a new residential and small business precinct
- Redeveloping a number of former industrial sites as new suburbs or high-rise apartments.

87. We also forecast continued changes in our customer mix during the 2016 regulatory period. These changes are characterised by declines in large industrial customers offset by significant growth in residential and commercial customer connections.

5.2 PRELIMINARY DECISION

88. We welcome the preliminary decision that it is satisfied that our connection forecast is a reasonable estimate.[64] In forming its view, the preliminary decision assessed JEN's:

- Actual and forecast customer contributions and historical spend
- Phased approach to produce its customer contributions forecast.

64 Ibid, p 6-9 and 6-56.

89. The preliminary decision concluded that JEN's:

- Residential and commercial/industrial sector volume growth rates represent a realistic expectation of connection activity[65]
- Assumed unit rates are reasonable[66]
- Forecast customer contributions are consistent with the requirements set out in Guidelines 14 and 15 and the soon to be introduced NER Chapter 5A, and reasonably reflect the contributions JEN is likely to receive in the 2016 regulatory period.[67]

90. Whilst the preliminary decision approved $5.95m (direct cost, $2015) for Melbourne Airport precinct as part of its augex forecast, the preliminary decision did not approve JEN's proposed $8.32m (direct cost, $2015) to install a new 66kV sub-transmission line to Melbourne Airport precinct included in JEN's connections April 2015 proposal. The preliminary decision stated that it was open to JEN providing updated information on the status of Melbourne Airport's request for additional capacity and more information on the combined cost-benefit of augmenting the existing sub-transmission loop and installing a new sub-transmission line.[68]

5.3 JEN'S RESPONSE AND THIS SUBMISSION

91. We welcome the preliminary decision on JEN's connections and customer contributions forecast. This submission maintains and builds on JEN's April 2015 proposal, provides new material relating to Melbourne Airport precinct project and clarifies its expenditure relating to special capital works projects.

92. To ensure we only propose allowances for efficient capex, we updated our customer number forecasts for latest information – see Attachments 7-7, 7-8 and 7-9.

5.3.1 CONNECTIONS CAPEX

93. We note that the preliminary decision asserted that it has re-categorised $5.95m (direct cost, $2015) of connection expenditure for the Melbourne Airport precinct expansion as augex—however, JEN had proposed that expenditure as augex (categorised under 'other projects') in our April 2015 proposal originally. JEN has since reassessed the needs of the Melbourne Airport precinct project and has updated its capex forecast to reflect new information that has come to light and re-categorised the expenditure as connections capex. Given that our total forecast capex and our categorisation of expenditure associated with this project have changed since our April 2015 proposal, JEN has summarised these changes in Table 5–4 below.

65 Ibid, p 6-61 and 6-62.

66 Ibid, p 6-63.

67 Ibid, p 6-67.

68 Ibid, p 6-52 and 6-53.

Table 5–4: Melbourne airport precinct project ($2015, $millions)

April 2015 proposal			Preliminary decision			This submission		
Project	*Category*	*Capex*	*Project*	*Category*	*Capex*	*Project*	*Category*	*Capex*
[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
[c-i-c]		[c-i-c]	[c-i-c]		[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c]
[c-i-c]		[c-i-c]			[c-i-c]			[c-i-c]

(1) The capex presented in Table 5–4 are direct costs (excludes capitalised overheads).

94. As noted in Table 5–4 JEN has also revised its forecast capex for the Melbourne Airport precinct project. Upon obtaining new information from Australia Pacific Airports Melbourne (**APAM**)—the customer who operates Melbourne Airport—and having undertaken some recent feasibility assessments, we have revised our forecast for this project since our April 2015 proposal. Attachment 7-19 provides our revised network development strategy with further details on the latest requirements and cost estimates for the Melbourne Airport precinct project.

95. Our forecast capex for the Melbourne Airport precinct project is driven by APAM's requirements and will be fully recovered through upfront customer contributions and future customer-specific tariffs, so we have re-categorised all the expenditure associated with this project as connections capex in this submission.

96. JEN's submission connections and customer contributions forecast for the 2016 regulatory period is $229.1m and $153.2m (both including capitalised overheads) respectively which achieves the Optimal NEO Position because:

- It will enable JEN to recover its efficient costs in providing its distribution services and meeting its regulatory obligations
- It incentivises JEN to efficiently invest in its network
- We have thoroughly assessed how best to prudently deliver our proposed capex 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 requirements in the NER, efficiently meet our obligations and customers' expectations, and promote the long-term interests of our consumers.

5.3.2 CUSTOMER CONTRIBUTIONS

97. We note that the preliminary decision did not include $29.9m (including capitalised overheads) of customer contributions associated with special capital works[69] relating to relocating assets. In our April 2015 proposal we sought to treat these costs consistently with the approach outlined in the Framework and Approach paper and therefore expect that the preliminary decision may have omitted these customer contributions as an oversight. Therefore, we have resubmitted our customer contributions included in April 2015 proposal.

98. In addition, the Victorian Government has announced its proposed partial implementation of NER chapter 5A for the economic regulation of connecting customers, moving away from the ESC's guideline 14 standard. The Bill[70] that gives effect to the adoption of Chapter 5A was introduced to parliament on 8 December 2015—the National Electricity (Victoria) Further Amendment Bill 2015. The Department of Economic Development, Jobs, Transport and Resources have advised us that the Bill will reach assent by March 2016.

99. The Bill provides for the implementation of Chapter 5A and Chapter 6 Part DA of the NER. These sections deal with the preparation of, requirements for, and approval of, connection policies to commence from a date yet to be proclaimed in 2016 but no later than 1 January 2017. The Bill also provides for new energy regulations to replace current Victorian regulatory arrangements on tendering policies on connection works and embedded generators and matters relating to undergrounding for distribution assets.

100. To reflect the new NER 5A provisions, we have provided an updated customer contribution forecast.

69 Categorised as repex.

70 National Electricity (Victoria) Further Amendment Bill 2015, 8 December 2015

6. FORECAST REPLACEMENT CAPEX

101. Table 6–1 below sets out our April 2015 proposal and submission repex forecast for distribution services compared with the preliminary decision.

Table 6–1: Forecast repex 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 repex are reported as 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

6.1 JEN'S APRIL 2015 PROPOSAL

102. Our April 2015 proposal forecast repex was $121m or 70% higher than we expect to spend over the 2011 regulatory period.

103. We noted in section 3.1 of attachment 7-3 of our April 2015 proposal that:

- Our network is ageing. A large proportion of our assets were installed in the 1960's and so with our assets coming to the end of their technical and economic lives we are entering the initial phase of a long term replacement cycle that we expect to extend across the next three regulatory control periods
- Our replacement capex forecast has been developed with detailed knowledge of our asset base, including the condition of the existing assets through actual condition monitoring and lifecycle optimisation
- Our forecast volumes are required to maintain reliability at current levels and to arrest the trend in increasing asset failure rates. Our decisions to invest in asset replacement activities affect the level of services, cost and prices over a long time[71]
- We have developed our replacement capital forecasts by optimising our repex and ensuring there is no overlap and duplication between expenditure proposed under other capex categories (particularly between repex and augex)
- We apply best practice techniques to accurately assess the replacement needs of our network including Condition Based Risk Management (**CBRM**) asset health modelling and net economic cost benefit analysis-in addition to industry standard condition assessment tools.

6.2 PRELIMINARY DECISION

104. The preliminary decision accepted JEN's proposed repex of $224m (direct costs) as an amount that reasonably reflects the capex criteria.[72] In forming its view the preliminary decision:

[71] JEN, *Regulatory proposal for the 2016 regulatory period*, 30 April 2015, Attachment 7-6 20 year strategic asset management plan

- Analysed JEN's long term total repex trends
- Conducted predictive modelling of repex based on JEN's assets in commission (for approximately 51% of JEN's proposed business as usual repex forecasts)
- Considered a technical review of JEN's approach to forecasting, costs, work practices and risk management
- Considered various health indicators and comparative performance metrics (these indicators were not relied upon in making the preliminary decision but used to provide context).

105. The repex predictive modelling estimated $169m ($nominal) of repex when using JEN's historical unit costs, and $184m ($nominal) using forecast unit costs. The preliminary decision noted that both of these outcomes are above JEN's forecast of $114m ($nominal) for the six modelled asset categories, which suggests that JEN's repex forecast is likely to be a reasonable estimate.[73] Based on this conclusion, the preliminary decision included this amount in its alternative estimate of forecast capex.

106. In relation to other (un-modelled) repex categories, the preliminary decision stated that historical expenditure is a good indicator of the prudence and efficiency of the proposed expenditure due to the predictable and recurrent nature of the expenditure. The preliminary decision also recognised that there might be circumstances where there will be period-on-period changes to repex requirements that reflect the lumpiness of the installation assets in the past.[74]

107. The preliminary decision accepted JEN's proposed repex for pole top structures of $35m ($nominal), proposed repex for SCADA, protection and control equipment of $35m ($nominal) and other repex categories of $40m ($nominal) (JEN's un-modelled repex categories) as it considers these amounts are sufficient to meet business as usual requirements, and reasonably reflect the capital expenditure criteria.[75]

108. With regard to the technical review of JEN's approach to forecast costs, work practices and risk management, the AER engaged Energeia to assist it review JEN's forecast. Energeia could not confirm or deny that JEN's forecast repex is prudent and efficient due to the number and degree of significant risks and/or issues identified.[76]

6.3 JEN'S RESPONSE AND THIS SUBMISSION

109. We welcome the preliminary decision supporting JEN's proposed repex of $224m (direct costs). We agree with the preliminary decision that this amount reflects the capex criteria and that historical repex can provide a good guide for future repex requirements.[77]

110. As noted in section 4.3, JEN has re-categorised the Preston conversion project from augex to repex.

111. We agree with the preliminary decision that JEN's repex forecast is a reasonable estimate of repex for the six 'modelled' categories.[78] JEN notes that its submission repex is materially lower than the preliminary decision's modelled repex. JEN considers that this reflects efficiencies achieved to date but may also reflect variances in

72 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020*, Attachment 6 – Capital expenditure October 2015, p 6-10 and section B.4.1.

73 Ibid, p 6-80.

74 Ibid, p 6-80.

75 Ibid, p 6-81.

76 Ibid, p 6-74.

77 Ibid, p 6-10 and section B.4.1.

78 Ibid, p 6-80.

the categorisation of capex as repex or augex—noting that by comparison, the preliminary decision's alternative estimate for our augex forecast was materially lower (34.3%) than our April 2015 proposal[79].

112. In relation to the other un-modelled repex categories, we welcome the preliminary decision's acceptance of JEN's proposed repex for pole top structures of $35m ($nominal, direct costs), proposed repex for SCADA of $35m ($nominal, direct costs) and other repex categories of $40m ($nominal, direct costs), or total $110m ($nominal, direct costs). JEN agrees with the preliminary decision that this amount is sufficient for JEN to meet its business as usual requirements, and that this amount reasonably reflects the capital expenditure criteria.

113. JEN's submission repex forecast for the 2016 regulatory period is $336.4m (including capitalised overheads) which we consider necessary to target the Optimal NEO Position because:

a) It will enable JEN to recover its efficient costs in providing its distribution services and meeting its regulatory obligations

b) It incentivises JEN to efficiently invest in its network

c) JEN will be able to maintain the quality and reliability of supply to its consumers

d) This forecast is driven by the need to increase our replacement program with targeted investments to replace our oldest failure-prone assets to ensure they do not cost our customers more in the future or jeopardise our safety and service levels.

e) We have thoroughly assessed how best to prudently deliver our proposed capex 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 requirements in the NER, efficiently meet our obligations and customers' expectations, and promote the long-term interests of our customers.

6.3.1 PREDICTIVE MODELLING: REPEX

114. The preliminary decision indicated that the Preston conversion project has characteristics that warrant categorisation as repex rather than augex noting that:

> *"We have not included the proposed capex for this project [Preston conversion] in our alternative estimate of Jemena's augex requirements. Based on Jemena's documentation, we are not satisfied that this project is justified by the need to expand the capacity or capability of the network. It is not clear that Jemena would have proposed this augmentation project if it were not for its assessment of the condition of relevant assets. As Jemena has not appropriately justified the need for the expenditure on the basis of an augmentation drivers, we have not included it within our alternative estimate of augex[80]".*

115. JEN acknowledges that in the current stage of the Preston conversion project's lifecycle, the replacement drivers (asset condition) are stronger than those to augment due to capacity constraints. Considering this and advice received from our independent engineering experts—WSPPB, JEN has re-categorised the Preston conversion project as repex in this submission, doing so has implications for JEN's repex predictive modelling.[81]

116. JEN requested Dr Brian Nuttall to prepare an addendum to the report he produced for JEN's April 2015 proposal (see Attachment 7-11 of our April 2015 proposal). This addendum is provided at Attachment 7-10 of

79 Ibid, p 6-37.

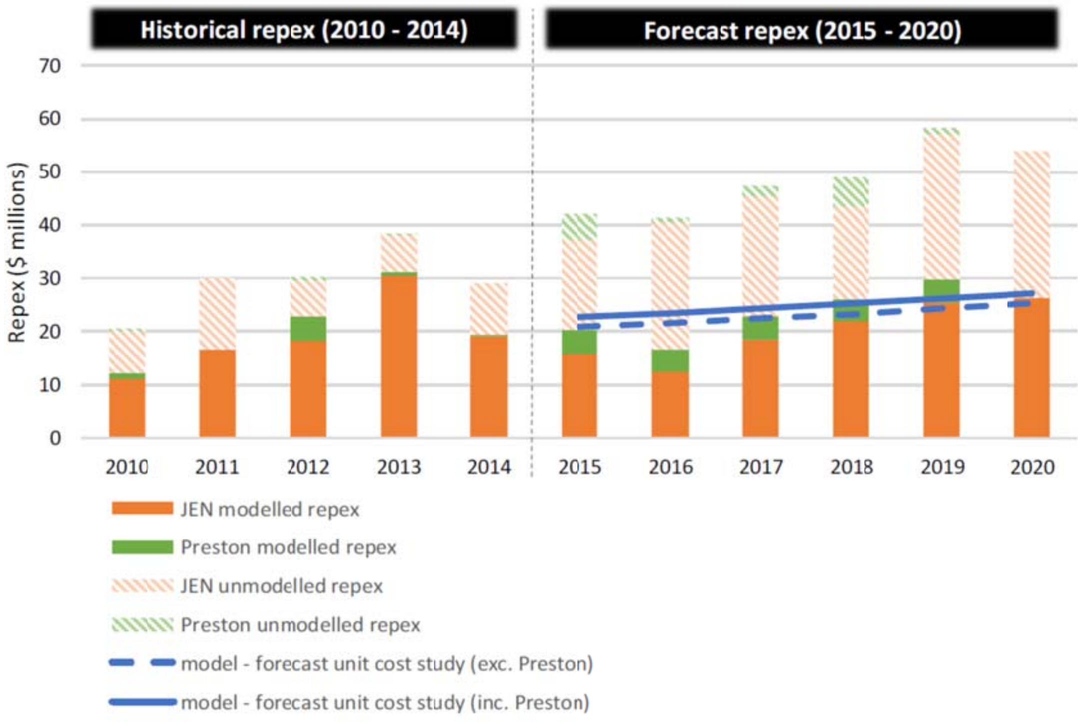
80 Ibid, p 6-53.

81 We have provided amended RIN templates 2.2 and 5.2 at Attachment 7-21 in this submission, that reallocate the historical costs of the Preston conversion project from augex to repex.

this submission and presents JEN's re-calibrated repex forecast including the historical and forecast expenditure associated with the Preston conversion project as repex (note: this was entirely categorised as augex in our April 2015 proposal).

117. Figure 6–1 below presents JEN's recalibrated forecast and indicates that if the AER applied the same predictive modelling approach as in the preliminary decision—ie. calibrate asset lives using two unit cost assumptions, JEN's own historical and forecast unit costs—then JEN's repex forecast would still be lower than both of the two calibrates scenarios. This confirms our repex forecast is a reasonable estimate of capex for the six modelled expenditure categories that are assessed.[82]

Figure 6–1: Nuttall Consulting – JEN revised repex forecast



Source: Attachment 7-10, *Nuttall Consulting Addendum to April 2015 repex report*

[82] Ibid, p 6-80.

7. CAPITALISED OVERHEADS

7.1 JEN'S APRIL 2015 PROPOSAL

118. Table 7–1 below sets out our April 2015 proposal and submission capitalised overheads forecast for distribution services compared with the preliminary decision.

Table 7–1: 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**

119. JEN's forecast capitalised overheads are determined by applying JEN's Cost Allocation Methodology (**CAM**).[83]

7.2 PRELIMINARY DECISION

120. The preliminary decision did not accept JEN's proposed capitalised overheads of $168.8m ($2015), but instead reduced the capitalised overheads to account for the reduced scale of the preliminary decision's substituted capex, this adjustment provides JEN $164.4m ($2015) in capitalised overheads.[84]

121. The preliminary decision has accounted for there being a fixed proportion of capitalised overheads based on an assumed 75 per cent fixed component and 25 per cent variable component. If JEN does not agree with this split, the preliminary decision requested JEN to provide evidence of a more appropriate split in its Submission.[85]

122. The preliminary decision was satisfied that its substituted capitalised overheads amount reasonably reflects the capex criteria.[86]

7.3 JEN'S RESPONSE AND THIS SUBMISSION

123. We accept the preliminary decision that it is not necessary to account for the way the CAM allocates overheads between capex and opex in making this decision given that opex is set based on the efficient level of opex inclusive of overheads.[87]

124. JEN accepts the preliminary decision model and approach to adjusting the forecast capitalised for the 2016 regulatory period. JEN has therefore adjusted its capitalised overheads forecast for this submission using the

83 JEN, *2016-20 Electricity Distribution Price Review, Regulatory Proposal, Attachment 7-9, JEN cost allocation methodology*, 30 April 2015.

84 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 6 – Capital expenditure October 2015*, p 6-10.

85 Ibid, p 6-93.

86 Ibid, p 6-93.

87 Ibid, p 6-93.

preliminary decision method resulting in $169m over 2016 regulatory period to target the Optimal NEO Position because:

- It will enable JEN to recover its efficient costs in providing its distribution services and meeting its regulatory obligations
- It incentivises JEN to efficiently invest in its network.

8. FORECAST NON NETWORK CAPEX

125. Table 8–1 below sets out our April 2015 proposal and submission non-network capex forecast for distribution services compared with the preliminary decision.

Table 8–1: Forecast non-network 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) JEN's April 2015 proposal is included in section 3.4 of Attachment 7-3 of our April 2015 proposal. JEN does not propose to apply capitalised overheads to non-network capex.

8.1 JEN'S APRIL 2015 PROPOSAL

126. Our non-network capex includes expenditure on information and communications technology (**ICT**), and other capex on motor vehicles, tools and equipment, buildings and property.

127. We noted in section 3.4.1 of attachment 7-3 of our April 2015 proposal that the main drivers of increased non-network IT expenditure over the 2016 regulatory period (relative to the 2011 regulatory period) include the need to:

- Sustain the IT asset functionality through upgrades to optimise asset performance and provide for growth despite a number of our main IT software and hardware licenses having increased in price in real terms, relative to the 2011 regulatory period
- Replace 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 purpose
- Add new systems and technologies and extend the use or functionality of existing systems to modernise our IT capability in areas where benchmarking against comparable businesses has identified some gaps.

8.2 PRELIMINARY DECISION

128. We welcome the acceptance in the preliminary decision of forecast non-network capex of $137.2m (direct costs) as a reasonable estimate of the efficient costs a prudent operator would require for this category.[88]

129. Specifically, the preliminary decision accepted that:

- ICT capex is likely to reflect the high level drivers of expenditure, and as such reflect a reasonable estimate of efficient costs[89]

88 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 6 – Capital expenditure October 2015*, p 6-10 and 6-94.

89 Ibid, p 6-97.

- Motor vehicles capex is likely to reflect the high level drivers of expenditure, and represents a reasonable estimate of efficient costs[90]
- Broadmeadows depot redevelopment capex proposed reasonably reflects the efficient costs of a prudent operator as evidenced by JEN's demonstration of the need for further investment to redevelop the Broadmeadows site following completion of the new Tullamarine depot in 2014 and the supporting financial case.[91]

130. JEN accepts the preliminary decision approach to include the forecast property disposal arising from the Broadmeadows depot redevelopment and therefore is reflected in our post-tax revenue model for the 2016 regulatory period.

8.3 JEN'S RESPONSE AND THIS SUBMISSION

131. JEN welcomes the preliminary decision on its non-network capex forecast for the 2016 regulatory period. Accordingly, this submission maintains the non-network forecast capex submitted in our April 2015 proposal however also seeks additional capex for the AEMC's Power of Choice program and the capex associated with the IT project to report actual RIN data.

132. Our lower forecast non-network other capex for the 2016 regulatory period (relative to the 2011 regulatory period) is driven by a reduction in property and buildings expenditure. The most significant proposed property development in the 2016 regulatory period is a project to redevelop our Broadmeadows depot in 2016 to reduce the size but increase the functionality of the depot. Much of our motor vehicles and plant assets are within a replacement phase of their lifecycle and so we proposed to replace or rebuild 213 motor vehicles and plant.

133. JEN's submission non-network capex forecast for the 2016 regulatory period is $161.7m (direct costs) which targets the Optimal NEO Position because:

- It will enable JEN to recover its efficient costs in providing its distribution services and meeting its regulatory obligations
- It incentivises JEN to efficiently invest in its network
- We have thoroughly assessed how best to prudently deliver our proposed capex program to ensure that the cost of our investments is minimised and timing is optimised. We submit that the program represents the level of expenditure necessary to comply with requirements in the NER, efficiently meet our obligations and customers' expectations, and promote the long-term interests of our customers.

8.3.1 POWER OF CHOICE

134. Substantial reforms to the National Electricity Market are currently underway following recommendations to the state and federal governments by the AEMC "Power of Choice review – giving consumers options in the way they use electricity."[92]

135. JEN's non-network capex forecast in this submission includes $25.39m (direct costs) to comply with the rule changes determined by the AEMC under the Power of Choice review (see Attachments 7-17 and 7-18 of this submission). This expenditure was not included within the forecast capex in our April 2015 proposal as we

[90] Ibid, p 6-97.

[91] Ibid, p 6-99.

[92] AEMC, *Power of choice review - giving consumers options in the way they use electricity*, 30 November 2012.

proposed to recover expenditure associated with this review via pass through events.[93] At the time, JEN's view was based upon the suite of rule changes underpinning the broader Power of Choice program still mostly being draft rule changes and therefore had some uncertainty associated with their scope and cost. Since then, the AEMC has delivered final rule changes on a number of the Power of Choice activities that provide JEN with sufficient certainty to include the expenditure within our opex and capex forecast.

136. JEN's Power of Choice forecast capex includes expenditure associated with the following rule changes:

1. Metering competition - On 26 November 2015, the AEMC made a final rule that will open up competition in metering services and will give consumers more opportunities to access a wider range of services[94]. The Metering Competition rule changes lay the foundation for a market-led approach to the deployment of smart meters.

2. Customer access to data - On 6 November 2014, the AEMC made new rules to make it easier for consumers to obtain information about their electricity consumption from distribution network companies and retailers in an easy-to-understand, affordable and timely way so that they can make more informed choices about energy products and services.[95]

3. Shared market protocol - On 8 October 2015 the AEMC published its final advice on the implementation of a shared market protocol. JEN expects the 'Implementation advice on the shared market protocol' Rule change to be complete by May 2016 with a proposed start date of 1 December 2017 to coincide with the metering competition rules commencing. This rule change will mandate a set of services, service level requirements, transport and formatting rules that are primarily intended to facilitate service requests and responses in regard to advanced metering services. Based on the design and linkages to operating in the NEM, this change to be inextricably linked to the metering competition rule change.

4. Distribution network pricing - On 27 November 2014, the AEMC made a new rule to require network businesses to set prices that reflect the efficient cost of providing network services to individual consumers.[96] The distribution network pricing arrangements rule change establishes four new pricing principles for distribution businesses so the prices reflect the efficient costs of providing network services to each consumer. This will allow consumers to compare the value they place on using the network with the costs of using it.

137. Table 8–2 below sets out JEN's incremental forecast capex in this submission necessary to comply with the regulatory changes associated with the Power of Choice review.

Table 8–2: Power of Choice expenditure ($2015, millions)

Power of Choice rule change activities	2016 regulatory period					
	2016	2017	2018	2019	2020	Total
Metering competition (MC) and shared market protocol (SMP)	4.85	15.74	-	-	-	**20.59**
Customer access to data (CAD)	1.88	-	-	-	-	**1.88**
Distribution network pricing (DNP)	2.54	0.38	-	-	-	**2.92**

93 JEN, *2016-20 Electricity Distribution Price Review Regulatory Proposal, Attachment 5-4, Risk Management Framework, Confidential*, 30 April 2015.

94 AEMC, *Schedules 1 and 5 of the National Electricity Amendment (Expanding competition in metering and related services) Rule 2015 No.12*, 26 November 2015.

95 AEMC, *National Electricity Amendment (Customer access to information about their energy consumption) Rule 2014,* 6 November 2014.

96 National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014.

Power of Choice rule change activities	2016 regulatory period	
Total		**25.39**

138. See Attachments 7-17 and 7-18 of this submission for the detailed business cases supporting JEN's Power of Choice review forecast capex.

8.3.2 REPORTING ACTUAL RIN DATA

139. Over the 2011 regulatory period JEN has progressively improved its reporting and data analytics capabilities to assist us to better collect the information, in the form requested by the AER, in Regulatory Information Notices (**RINs**) by providing the systems that can capture this data. The scope of our forecast IT software and hardware expenditure includes provisions that allow us to maintain an IT system that has the capability to scale up or down in the complexity of reports produced—for business intelligence, RINs, or alike—as the business' needs adapt over time. We have developed a system that allows us this flexibility and our submission non-network IT capex ensures these capabilities extend into the 2016 regulatory period.

140. With regard to RINs reporting specifically, our July 2015 submission[97] included a step change proposal for $19.65m ($2015) of additional operating expenditure to allow JEN to report actual RIN data. As part of this submission, we have revised our cost estimate (see Attachments 8-2 and 8-10, 8-11 and 8-12 of this submission) downwards from $19.65m ($2015) of opex to $5.88m ($2015) of opex and $2.15m ($2015) of non-network IT capex in this submission.[98] Specifically, we expanded the scope of an IT project in our April 2015 proposal[99] to provide for additional back-end system upgrades to report actual RIN data. The minor addition in non-network IT capex (and material reduction in opex) reflects an opex to capex trade-off that minimises the net cost to our customers. See the business case provided at Attachment 8-11 for further detail of the required incremental capex to report actual RIN data.

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

98 Refer to Attachment 7-2 of this submission, project ID P416.

99 Refer to Attachment 7-4 of our April 2015 proposal, project ID P092.

9. COMPLIANCE WITH THE NER

9.1 WHY THE TOTAL FORECAST CAPEX IS REQUIRED TO ACHIEVE EACH OF THE CAPEX OBJECTIVES IN 6.5.7(A)

141. We have established capex forecasts that achieve the capital expenditure objectives specified in the NER. We have primarily achieved this by (among other things):

- Conducting detailed analysis of the actual condition and age of our assets—details are provided in Attachment 7-3 of our April 2015 proposal
- Assessing the sufficiency of our current compliance with regulatory obligations to identify required investments for corrective actions—in addition to the information provided in Attachment 7-3 of our April 2015 proposal, we sought independent engineering expert advice to assess our recommended technical solutions to a number of augmentation and replacement projects and reviewed of our approach to source non-network alternatives to network capital expenditure
- Assessing foreseeable changes in the operating environment that will place upward pressure on our forecast capex such as changing climate conditions (which are increasingly affecting our network's performance), lengthening and intensifying the bushfire season,[100] and creating conditions conducive to pole fires. In addition, increasingly frequent severe weather events (including wind storms and heat waves) mean we need to undertake programs to minimise the fire risk associated with our assets. Our proposed safety replacement programs in the 2016 regulatory period will ensure we continue to maintain the safety of our customers, community and staff and the reliability of our services
- Identifying new or changed obligations that will affect our forecast capex program
- Quantifying customer initiated requests to connect to our network as informed by various expert demand reports.

142. Table 9–1 summarises how we have complied with the capital expenditure objectives.

Table 9–1: Compliance with the capital expenditure objectives

Capital expenditure objective	NER	Actions to ensure compliance
Meets or manages the expected demand for standard control services over the regulatory period	6.5.7(a)(1)	We have forecast our relevant capex categories to take into account the growth effects of expert peak demand, consumption and customer number reports prepared by ACIL Allen (see Attachments 7-4 to7-9). These top down forecasts also reconcile to our own bottom up spatial demand forecasts (see Attachment 7-4) and ensure that are forecasts are allocatively efficient.
Complies with all applicable regulatory obligations or requirements associated with the provision of	6.5.7(a)(2)	We have assessed our current compliance processes against our obligations as well as assess corrective actions and additional new obligations. Our existing systems and

100 Climate Council , *Be prepared: Climate change and the Victorian bushfire threat* , 2014

Capital expenditure objective	NER	Actions to ensure compliance
standard control services		processes—including our international best practice governance framework[101]—ensures that our compliance obligations are well managed. Attachment 8-2 to our submission sets out our proposed step changes for new regulatory obligations or requirements associated with the provision of standard control services.
Maintain the quality, reliability and security of supply of standard control services	6.5.7(a)(3)	We have prepared a comprehensive 7 year asset management plan (see Attachment 7-5 of our April 2015 proposal) for our network assets and also a 7 year IT asset management plan (see Attachment 7-7 of our April 2015 proposal) to guide our IT expenditure. The associated capex forecasts within the asset management plans have considered the impact of our changing operating environment, the actual condition of our assets and their age, the current and forecast utilisation of our assets and the effect these influences have on the quality, reliability and security of supply. We have also provided a copy of our 20 year strategic asset management plan at Attachment 7-6 of our April 2015 proposal which includes scenario analysis (see section 10.2) where we assessed changes in the level of capex (and operating expenditure) and their associated impact on the average cost to our customers over three time horizons. We have also consulted extensively with our customers and interested stakeholders on our forecast capital plan and their preferences around service levels.
Maintain the safety of the distribution system through the supply of standard control services	6.5.7(a)(4)	We have prepared a comprehensive 7 year asset management plan (see Attachment 7-5 of our April 2015 proposal) for our network assets. The associated capex forecasts within the asset management plan have considered the impact of our changing operating environment, the actual condition of our assets and their age, the current and forecast utilisation of our assets and the effect these influences have on the quality, reliability and security of the system. Additional considerations include trends of asset failures and customer reports of safety issues as they impact potential future network safety issues. Safety is our number one priority. We have forecast the required capex to comply with our Electricity Safety Management Scheme (**ESMS**). Our ESMS, of which Energy Safe Victoria has oversight, assists ensure the safety of the distribution system is maintained.

9.2 HOW OUR TOTAL CAPEX FORECAST REASONABLY REFLECTS EACH OF THE CAPEX CRITERIA IN 6.5.7(C)

143. We have established our capex to comply with the capital expenditure criteria specified in the NER. We have primarily achieved this by:

101 We attained PAS 55 accreditation in August 2014, and at April 2015 were one of only three Australian businesses to have done so. The accreditation applies to our asset management system, which covers activities relating to the creation, acquisition, operation and maintenance of electricity distribution assets.

- Developing our capex forecasts in accordance with our PAS 55 accredited asset management framework and governance structures that assist ensure that the input costs to our capex forecasts are the efficient costs of achieving the capital expenditure objectives.
- Developing our forecasts based on our robust cost estimation methodology (see Attachment 7-10 of our April 2015 proposal) that ensures all the program and project cost estimates within our forecasts have been developed according to our top down assessment approaches (using historical cost data, recent tender prices and contract prices) and bottom up cost estimates (using schedules of rates negotiated under competitive tender and panel arrangements). This process ensures our forecasts are productively efficient.
- Ensuring a cross section of our forecast unit rates for routine capital programs and major projects were costed by an independent expert and assessed for reasonableness—the majority of JEN's programs and projects outperformed the independent expert's benchmark indicating our forecasts are productively efficient and that we have forecast only those costs that a prudent operator would incur to achieve the capital expenditure objectives.
- Updated our procurement approach by establishing new competitive tenders, and refreshed our panel of preferred suppliers to provide us access to an external resource base with specialised expertise at best market rates to achieve productive efficiency (see Attachment 7-8 of our April 2015 proposal).
- Developing a detailed delivery strategy which ensures that our forecast program of work can be delivered as planned, without exposing JEN to resource constraints and additional costs (see Attachment 7-8 of our April 2015 proposal). This strategy provides a plan for our forecast program of work to be delivered within an optimal time frame and at efficient cost by utilising our own work force to its optimum capacity and the resources available from service agreements through competitive tenders and long standing supply contracts. This document confirms that our capital expenditure forecast reflects a realistic expectation of our demand forecasts and cost inputs.

9.3 HOW OUR TOTAL FORECAST ACCOUNTS FOR THE CAPEX FACTORS IN 6.5.7(E)

144. The NER set out the capital expenditure factors which the AER must have regard to when deciding whether or not to approve our capex forecast. Table 9–2 summarises points we consider relevant to these factors.

Table 9–2: Compliance with capital expenditure factors

Capital expenditure factors	NER	JEN comments
The most recent *annual benchmarking report* that has been *published* under rule 6.27 and the benchmark capital expenditure that would be incurred by an efficient *Distribution Network Service Provider* over the relevant *regulatory control period*	6.5.7(e)(4)	Based on its first annual benchmarking report,[102] the preliminary decision found that over 2006 to 2013 JEN performs relatively well on partial factors productivity of capital and Multilateral Total Factor Productivity (MTFP), and over 2008 to 2012 well in terms of capex per customer and capex per maximum demand. Further, the AER found that JEN incurs relatively low opex and total cost per customer. Based on the 2015 benchmarking report,[103] our performance is maintained in the top quartile of efficient businesses for the MTFP measure (Figure 4) and we benchmark as the second most efficient distribution network service provider in the country for the capex partial performance indicator (Figure 5). These benchmarks reveal that despite our scale disadvantage, we are

[102] AER, *Electricity distribution network service providers, annual benchmarking report*, November 2014.

[103] AER, *Electricity distribution network service providers, annual benchmarking report*, November 2015

Capital expenditure factors	NER	JEN comments
		managing to produce more with less, relative to our peers.
The actual and expected capital expenditure of the *Distribution Network Service Provider* during any preceding *regulatory control periods*	6.5.7(e)(5)	JEN has a proven record of accurately forecasting what we require to safely and reliably run our network. See the detailed explanation of our historical capex incurred by year in Attachment 7-1 and a broader description in chapter 7 of our April 2015 proposal. The preliminary decision considered JEN's forecast capex against the long-term historical trend in capex levels. The preliminary decision considered its analysis in making decisions on each capex component.
The extent to which the capital expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the *Distribution Network Service Provider* in the course of its engagement with electricity consumers	6.5.7(e)(5A)	We consulted extensively with our customers and broader stakeholders while developing our capex forecasts (see box 7-2 in our April 2015 proposal). Chapters 3 and 4 of our April 2015 proposal, and particularly Attachment 4-1, summarise details of their concerns, and how their feedback has influenced our capital expenditure forecast.
The relative prices of operating and capital inputs	6.5.7(e)(6)	We rely on lifecycle management planning for each asset class, which: • considers all the strategies and options over the entire asset life from planning to disposal to deliver the lowest long term sustainable costs to deliver our corporate objectives and business plan • focusses on ensuring effectiveness and efficiency in maintenance (operating expenditure) and replacement (capex) of the network assets based on analysis that balances issues relating to safety, cost, risk and reliability. Additionally, we have relied upon the same input cost escalators for capital and operating expenditure (see section 3.3.1 of Attachment 8-01 and chapter 2 of Attachment 7-01) and have adopted the preliminary decision on them.
The substitution possibilities between operating and capital expenditure	6.5.7(e)(7)	Part of business as usual operations include analysing ways to optimise the economic life of our assets; various examples of this analysis are included in our regulatory proposal. Typically, we assess whether asset replacement can be deferred by substituting capex for further maintenance—where it leads to lower long-term average costs to our customers-and we also consider the safety and reliability risks associated with these decisions. We also assess whether network augmentation projects can be deferred by utilising non-network alternatives—through demand management for example (see Attachment 7-15 of this submission). JEN takes seriously its obligations in making expenditure decisions and looks to optimise these on a continual basis. This may result in spending opex instead of planned capex—or vice-versa—depending on the prevailing circumstances. JEN is adept at delivering against this trade-off objective, being one of

Capital expenditure factors	NER	JEN comments
		the highest ranked electricity distribution businesses for managing the trade-off requirement (see Attachment 2-1, section 4.3 of our April 2015 proposal). Also, the new Capital Expenditure Sharing Scheme (**CESS**) creates symmetrical incentives across opex and capex, and so we will continue to search for ways to optimise the substitution possibilities between opex and capex.
Whether the capital expenditure forecast is consistent with any incentive scheme or schemes that apply to the *Distribution Network Service Provider* under clauses 6.5.8A or 6.6.2 to 6.6.4	6.5.7(e)(8)	Our capex forecasts are consistent with the CESS, the STPIS and the small-scale incentive scheme. Our forecasts do not include capex to fund improvements to our levels of reliability, but only capex to maintain reliability. The STPIS' self-funding mechanism incentivises us appropriately in this regard. We maintain rigorous approval and financial evaluation processes for proposals to commit capital funding. Our augmentation and connection projects routinely apply economic cost benefit analysis for all significant capital proposals. We have also applied economic cost benefit analysis to some replacement projects that meet agreed criteria, and where costs and benefits can be calculated with respect to the whole supply chain. All realistic options are assessed in these analyses and all costs, savings (both capital and operating) and revenues relevant to each option are included. Our analysis is holistic in that it captures all the incremental marginal benefits and marginal costs and the incremental impact of the relevant incentive schemes is included in our investment analysis. Furthermore, as a privately owned business, we have other natural incentives not to overspend our allowance, as we bear the financing costs and depreciation expense for doing so.
The extent the capital expenditure forecast is referable to arrangements with a person other than the *Distribution Network Service Provider* that, in the opinion of the *AER*, do not reflect arm's length terms	6.5.7(e)(9)	As discussed in section 19 of our response to Schedule 1 of the EDPR RIN included in the supporting documents submitted with our April 2015 proposal, we have an established outsourcing arrangement that reflects prudent commercial terms with Jemena Asset Management (**JAM**) and Zinfra. The preliminary decision said that it did not have any evidence to indicate that any of JEN's arrangements do not reflect arm's length terms.
Whether the capital expenditure forecast includes an amount relating to a project that should more appropriately be included as a *contingent project* under clause 6.6A.1(b)	6.5.7(e)(9A)	Our submission forecast capex does not include an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b). The preliminary decision did not identify any such amounts that should be more appropriately treated as a contingent project.
The extent the *Distribution Network Service Provider* has considered, and made provision for, efficient and prudent non-network alternatives	6.5.7(e)(10)	As stated in our response to 21.2 of Schedule 1 of the EDPR RIN we propose to undertake two demand response projects in the 2016 regulatory period with the objective of managing network risk and providing the best value solution to our customers. Our 2014 Distribution Annual Planning Report (provided with the capex supporting documents with our EDPR RIN response) identifies the two intended locations for targeted

Capital expenditure factors	NER	JEN comments
		demand response programs. JEN engaged Advisian to provide an external review of its demand management options assessment practices. Advisian confirmed that JEN's demand management options assessment approach is comparable to the practices of other Australian distribution networks and that JEN considers demand management options for all of its major augmentation projects, including documenting the reasons for not proceeding with a non-network option at each stage of the assessment (see Attachment 7-15).
Any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s)	6.5.7(e)(11)	Our capex forecast includes a number of projects that are subject to the RIT-D. **RIT-D** processes will be conducted for the major augmentation zone substation project at Craigieburn, and are in process for Flemington and Sunbury.
Any other factor the *AER* considers relevant and which the *AER* has notified the *Distribution Network Service Provider* in writing, prior to the submission of its revised *regulatory proposal* under clause 6.10.3, is a *capital expenditure factor*	6.5.7(e)(12)	We have provided information to respond to the assessment techniques spelled out in the AER's expenditure assessment guideline. The preliminary decision did not identify any other capex factor relevant.

(2) Italicised terms are as per the NER.

9.4 S6.1.1(6) INFORMATION AND MATTERS RELATING TO CAPEX

145. In relation to building block proposal the NER states:

A building block proposal must contain at least the following information and matters:

(6) capital expenditure for each of the past regulatory years of the previous and current regulatory control period, and the expected capital expenditure for each of the last two regulatory years of the current regulatory control period, categorised in the same way as for the capital expenditure forecast and separately identifying for each such regulatory year:

(i) margins paid or expected to be paid by the Distribution Network Service Provider in circumstances where those margins are referable to arrangements that do not reflect arm's length terms; and

(ii) expenditure that should have been treated as operating expenditure in accordance with the policy submitted under paragraph (8) for that regulatory year;

9.4.1 JEN'S RESPONSE

JEN has set out in Attachment 7-3 of its April 2015 proposal how it complied with the S6.1.1(6) requirements.