Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review Regulatory Proposal

Revocation and substitution submission

Attachment 8-1 Operating expenditure forecasting method and base year efficiency

Public

6 January 2015

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ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
BIS	BIS Shrapnel
CAM	Cost Allocation Methodology
CPI	Consumer Price Index
DAE	Deloitte Access Economics
DMIA	Demand Management Incentive Allowance
DMIS	Demand Management Incentive Scheme
EBSS	Efficiency Benefit Sharing Scheme
EDPR	Electricity Distribution Price Review
ESC	Essential Services Commission
F&A	Framework and Approach
GSL	Guaranteed Service Level
IT	Information Technology
MTFP	Multilateral Total Factor Productivity
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
OPEX	Operating Expenditure
Optimal NEO Position	The position which contributes to the achievement of the NEO to the greatest degree and best promotes the long term interests of consumers of electricity
PTRM	Post-Tax Revenue Model
RINs	Regulation Information Notices
STPIS	Service Target Performance Incentive Scheme
WPI	Wage Price Index

OVERVIEW

Key messages

- We welcome the preliminary decision's recognition of the efficiency of our past operating expenditure (**opex**) and acceptance of our 2014 revealed costs as our **base year** opex in developing its alternative estimate of JEN's opex forecast. In addition, we welcome the recognition of our responsiveness to the incentive framework, which provides us with incentives to improve our efficiency, sharing these with our customers—these efficiencies are calculated to be $24.8m ($2015) over the 2011 regulatory period through the efficiency benefit sharing scheme (**EBSS**).
- We are concerned that the preliminary decision finds there are very few changes in the external environment that require a step change in opex[1]. We accept the preliminary decision's approach to six of the 13 opex **step changes** we proposed in our April 2015 proposal. However, the preliminary decision's exclusion of the remaining seven step changes—including RIN reporting requirements, vegetation management and vulnerable customer initiatives valued by our customers—does not promote the **Optimal NEO Position**[2] given that there must be an opportunity for JEN to recover its efficient costs of new regulatory or legislative obligations. We have provided further information to address the concerns of the Australian Energy Regulator (**AER**) as set out in the preliminary decision.
- In addition to the step changes outlined in our April 2015 proposal, we are raising additional items in this submission concerning: the December 2015 increase in Guaranteed Service Level (**GSL**) obligations, new obligations arising from the Australian Energy Market Commission (**AEMC**)'s Power of Choice program and Victoria's implementation of National Electricity Rules (**NER**) Chapter 5A obligations for connecting new consumers.
- We have responded to the concerns raised in the preliminary decision and revised our **step changes** downward from $60.2m[3] to $27.7m ($2015).
- We accept the method used to **trend** the base year over the 2016 regulatory period, however, we do not agree with the forecast customer numbers or ratcheted peak demand used in calculating output growth forecasts in the preliminary decision. In this submission, we outline the reasons for our objection and provide a more consistent data set to develop a more reliable trend escalator.
- We do not agree with the preliminary decision to reclassify $60.9m ($2015) of network systems and customer support opex from the former smart meter roll out cost pool (**metering services opex**) back to standard control distribution services. The network services opex we had reclassified to distribution services is for opex associated with our core distribution services which we will need to incur regardless of who provides metering services. In this submission, we have included $46.5m ($2015) of costs in our forecast opex for distribution services that would otherwise be classified in metering service costs (see Attachment 9-1 for more detail).

1. The April 2015 proposal (together with any supporting material contained or referred to in the April 2015 proposal) is incorporated into, and forms part of this submission.

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

[2] 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

[3] JEN proposed an additional $29.9m ($2015) in step changes to its April 2015 proposal of $30.3m ($2015) in its submission *Jemena Electricity Network Ltd 2016-20 regulatory proposal*, 13 July 2015, increasing its total opex forecast to $528.9m ($2015) including debt raising costs.

2. Table OV–1 below sets out our April 2015 proposal and submission forecast opex for distribution services compared with the preliminary decision.

Table OV–1: Forecast opex for distribution services ($2015, $millions)

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

(1) Opex includes debt-raising costs.

3. We have undertaken a thorough assessment to determine that our submission forecast opex represents the expenditure that would be required to achieve the requirements in the NER,[4] efficiently meet our obligations and customers' expectations and to promote the Optimal NEO Position.

VARIANCE TO 2011 REGULATORY PERIOD

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

- Unavoidable upward pressure on opex, including forecast real increases in our key input costs, forecast growth in key network characteristics such as ratcheted maximum demand and circuit length as well as customer numbers, with these factors representing $30.4m ($2015) or 8% of the increase in our forecast of opex over the 2016 regulatory period
- Additional inspection, maintenance, customer engagement and vulnerable customer assistance programs to ensure we continue to meet safety requirements and our customers' expectations, with these step changes in opex representing $21.8m ($2015) or 6% of the increase in our forecast opex over the 2016 regulatory period, and
- Additional regulatory reporting requirement through the AER's Category Analysis and Efficiency Benchmarking Regulation Information Notices (**RINs**) representing $5.9m ($2015) or 2% of the increase in our forecast of opex over the 2016 regulatory period.

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

- Supply abolishment costs (up to 100 amps) as distribution services consistent with the AER's Framework and Approach (**F&A**) paper[5]

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

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

- Certain network systems and customer support costs[6] that were temporarily recoverable under the AMI Order in Council now reverting back to the distribution services cost base given that the AMI Order in Council ends on 31 December 2015, and these activities being a necessary component of our distribution services in the 2016 regulatory period.

VARIANCE TO OUR APRIL 2015 PROPOSAL

6. The forecast opex in this submission for distribution services shown in Table OV–1 is $28.1m ($2015) or 5.6% lower than our total forecast opex in our April 2015 proposal. The main drivers of this decrease are refinements to our:

- **Base year** (down $17.7m, $2015)—taking into account refinement to lower our estimate of AMI Order in Council costs reclassified to distribution services (following feedback from the preliminary decision)
- **Step changes** (down $2.6m, $2015)—where we:
  - Removed four step changes (regulatory proposal costs, customer engagement costs, ESV/VESI code of practice changes and overhead switch inspection), consistent with the preliminary decision
  - Added three step changes for additional Essential Services Commission (**ESC**) obligations relating to GSL payments, enhancing RIN reporting capability and Victoria's implementation of the NER Chapter 5A obligations for connecting new customers
  - Refined our estimates, reducing the forecast for two step changes (enclosed substation inspection and vegetation management)[7]
- **Rate of change** (down $3.7m, $2015)—where we agreed with the preliminary decision in relation to the real price growth, no productivity growth and output growth drivers (but included our forecasts of customer numbers and ratcheting peak demand), and
- **Category specific forecasts** (down $4.1m, $2015)—agreeing with the debt raising cost benchmark in the preliminary decision.

VARIANCE TO THE PRELIINARY DECISION

7. The forecast opex for distribution services over the 2016 regulatory period shown in Table OV–1 is $80.8m ($2015) or 20.7% more than the allowed in the preliminary decision. The main drivers of this increase are refinements to:

- **Base year** (up $40.6m, $2015)—where we included costs associated with metering services required for our core distribution services, and updated the 2015 inflation forecast to 1.75% (compared to the preliminary decision placeholder assumption of 2.50%)
- **Step changes** (up $24.6m, $2015)—where we believe we require funding for:

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

7 This excludes our RIN reporting step change for $19.8m submitted on 13 July 2015.

- Additional inspection, maintenance, customer engagement and vulnerable customer assistance programs to ensure we continue to meet safety requirements and our customers' expectations, with these step changes
- Complying with new obligations in relation to RIN reporting and vegetation management to reflect the clarified expectations provided by the AER and ESV
- Complying with an increase in GSL obligations and new obligations relating to the Australian Energy Market Commission's Power of Choice program on giving consumers options in the way they use electricity, and
- Complying with Victoria's implementation of the NER Chapter 5A obligations for connecting new customers

- **Rate of change** (up $15.6m ,$2015), mainly due to differences in the escalation rates (within our output growth) for
  - Ratcheted maximum demand (see Attachment 7-4)
  - Customer numbers (see Attachment 7-7)
- **Category specific forecasts** (up $0.1m, $2015), due to higher debt raising costs required to fund additional capex related to the Power of Choice program.

8. Table OV–2 summarises our response to the preliminary decision.

Table OV–2: Overview of our submission response to the preliminary decision on forecast opex

Forecast opex category	Preliminary decision	Our response to the preliminary decision	JEN's submission
Base year efficiency	Accepted that we are efficient and approved our 2014 revealed costs as our base year	✓	Same as our April 2015 proposal
Service reclassification	Accepted our reclassification of supply abolishment costs but rejected our proposal to treat some network systems and customer support costs incurred under the Advanced Metering Infrastructure (**AMI**) Order in Council as distribution services	✗	Included the supply abolishment costs as per our April 2015 proposal but included the AMI Order in Council reclassification costs under a refined allocation method
Adjustments to our base year	Rejected some of our adjustments (e.g. some non-recurrent costs or self-insurance) and made some of its own such as removing movement in provisions	✓	Adopted the position in the preliminary decision
Rate of change	Substituted its own escalators and weightings	≈	Adopt the approach from the preliminary decision but have applied our forecast output growth drivers (e.g. customer numbers and/or ratcheted peak demand) consistently across this submission

Forecast opex category	Preliminary decision	Our response to the preliminary decision	JEN's submission
Step changes	Only approved two out of 13 step changes proposed	≈	We have responded to the concerns raised in the preliminary decision and revised our step changes downward from $60.2m to $27.7m ($2015)
Category specific forecasts	Approved guaranteed service level payments and debt raising costs	✓	Adopted the position in the preliminary decision

9. Based on its high level benchmarking metrics, the AER found that JEN is operating relatively efficiently compared to other electricity service providers in the National Electricity Market (**NEM**).[8] In particular, the AER found that:

- The multilateral total factor productivity (**MTFP**) index results indicate that JEN performs relatively well comparted to other service providers in the NEM[9]
- In its 2014 annual benchmarking report,[10] JEN appears to be one of the more efficient networks based on a number of partial performance indicators, in particular, JEN incurs relatively low opex and total cost per customer when compared to its peers—these findings support the general conclusion that there is no evidence of material inefficiency.[11]

10. In addition, JEN notes that the AER's November 2015 benchmarking report[12] is consistent with its 2014 findings that indicate that there is no evidence of material inefficiency for JEN.

11. The preliminary decision accepted that JEN's 2014 base year opex was efficient. However, it made slight adjustments to JEN's base year opex to that proposed by JEN.

12. In addition, the preliminary decision:

- Substituted JEN's proposed 2015 opex estimate
- Reclassified $60.9m ($2015, escalated) of metering services opex to alternative control services
- Disallowed $56.8m ($2015, escalated) of JEN's proposed $60.3m ($2015, escalated) for step changes[13]
- Did not accept JEN's proposed real price growth escalators and weightings and
- Did not accept JEN's proposed output growth drivers and productivity growth forecasts.

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8 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 7 – Operating expenditure October 2015*, p 7-23

9 Ibid, p 7-33

10 AER, *Electricity distribution network service providers, Annual benchmarking report*, November 2014

11 Ibid, p 7-37

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

13 In response to the new amendments that commenced in Victoria on 28 June 2015, JEN revised its step change from $5.63m to $15.89m ($2015) in its *Submission to Jemena Electricity Network Ltd 216-20 regulatory proposal*, 13 July 2015, page 1. In addition, JEN proposed an additional $19.65m for RIN related expenses in complying with the AER's RIN requirements (see Jemena, *Submission to its Regulatory proposal*, 13 July 2015, pages 3-6).

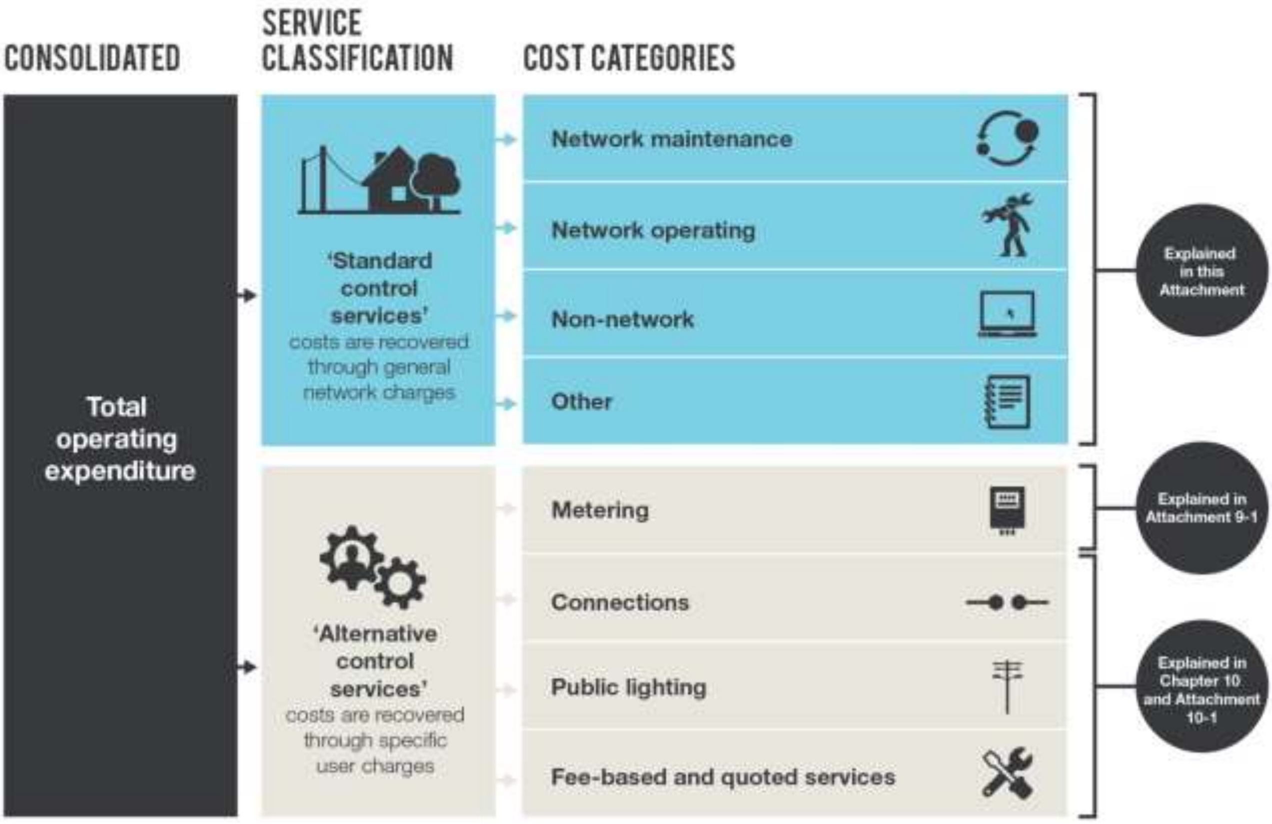
13. In revising our total opex forecasts, we have considered the preliminary decision and provided further information in this submission to address the concerns raised, particularly relating to step changes.

1. INTRODUCTION

14. Forecast opex is one of the building block costs used to calculate the annual revenue requirement (see Attachment 5-1 of this submission). We must propose the total opex we will require to provide our distribution services in each year of the 2016 regulatory period (see Table OV–1) that meets the operating expenditure 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).[14] This attachment sets out our submission opex forecasts for distribution services.

15. Our forecast opex for distribution services includes the costs of operating and maintaining our physical assets (for example, poles, wires and computer and billing systems), responding to emergencies (such as fallen trees on our lines), performing related customer functions and providing billing information to retailers (see opex categories outlined in Figure 1–1).

Figure 1–1: JEN's opex categories



(1) Opex relating to connections, public lighting and other alternative control services are explained in other attachments of this submission.

16. Our April 2015 proposal provided information about this expenditure as required by the NER and AER,[15] including our opex categories and the approach we have used to develop our opex forecast to ensure it is consistent with the costs that would be incurred by a prudent service provider acting efficiently.[16]

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14 NER Cl. 6.5.6.

15 NER Cl. 6.5.6 and schedule s 6.1.2; AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, December 2013; and RIN Cl. 3

17. In developing our submission opex forecast, we have taken into account the anticipated changes occurring in the energy market during and beyond the 2016 regulatory period and our customer preferences. We also have considered the preliminary decision.

18. The following sections of this attachment provide:

- Our submission forecast opex for distribution services in the 2016 regulatory period by cost category, and
- Further information on our submission opex forecast as required by the NER and AER, including the difference between this submission opex forecasts, the preliminary decision and our April 2015 proposal[17] opex forecast.

19. This document is structured as follows:

- Chapter 2 sets out our submission opex forecast
- Chapter 3 sets out our the key variables and assumptions we have used in developing our submission opex forecast
- Chapter 4 shows how our submission opex forecast complies with the NER, particularly the operating expenditure objectives and operating expenditure criteria, and it takes account of the operating expenditure factors along with other NER criteria for distribution services.

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

17 Attachment 8-2 of our April 2015 proposal.

2. SUBMISSION OPEX FORECAST

20. Our opex forecast programs for distribution services outlined in Table 2–1 represent a prudent and efficient level of expenditure required to meet our obligations, maintain existing service levels and to reflect our customers' preferences for the 2016 regulatory period.

Table 2–1: Submission opex forecast for distribution services by cost category ($2015, $millions)

Distribution services opex	2016	2017	2018	2019	2020	Total
Network maintenance	**18.21**	**18.51**	**18.83**	**19.23**	**18.10**	**92.88**
Routine maintenance	6.03	6.12	6.24	6.36	4.94	**29.69**
Non-routine maintenance	3.04	3.10	3.17	3.25	3.32	**15.88**
Emergency response	3.69	3.77	3.86	3.96	4.07	**19.35**
Vegetation management	5.45	5.52	5.55	5.66	5.77	**27.96**
Network operating	**53.66**	**50.74**	**51.77**	**53.08**	**54.40**	**263.65**
Network overheads	33.72	30.35	30.87	31.63	32.41	**158.98**
Corporate overheads (excluding IT)	19.94	20.39	20.91	21.45	21.99	**104.68**
Non-network	**19.27**	**19.80**	**19.80**	**20.31**	**20.82**	**100.00**
Information technology (**IT**)	14.60	15.01	14.89	15.28	15.67	**75.44**
Motor vehicles	0.55	0.56	0.58	0.59	0.61	**2.88**
Buildings and property	4.13	4.22	4.33	4.44	4.55	**21.67**
Other	**2.67**	**2.78**	**2.89**	**2.97**	**3.05**	**14.36**
Levies (incl. licence fees)	1.50	1.53	1.57	1.61	1.65	**7.87**
GSL payments	0.05	0.05	0.05	0.05	0.05	**0.26**
Demand side management	0.11	0.15	0.15	0.15	0.15	**0.71**
Self-insurance	0.39	0.40	0.41	0.42	0.43	**2.06**
Debt raising costs	0.62	0.65	0.70	0.73	0.76	**3.46**
Total forecast opex	**93.81**	**91.83**	**93.28**	**95.59**	**96.38**	**470.89**

21. Our opex forecasting model is included in Attachment 8-3 of this submission.

22. Our opex forecast set out in Table 2–1 above reflects our view that certain costs (currently categorised as AMI, mandated by the AMI Order in Council) which arose in the 2011 regulatory period and are a necessary component of our distribution services in the 2016 regulatory period. Service reclassification is discussed in section 2.1 in further detail.

23. Table 2–2 shows JEN's April 2015 proposal and submission opex forecast using the 'base, step, trend method', compared with the opex forecast in the preliminary decision.

Table 2–2: Forecast opex for our distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
April 2015 proposal						
Base year opex	85.35	85.35	85.35	85.35	85.35	**426.76**
Step changes	6.62	4.18	4.80	6.94	7.81	**30.34**
Escalation / rate of change	1.99	4.34	6.79	9.25	11.72	**34.10**
Category specific costs	1.41	1.48	1.56	1.64	1.72	**7.81**
Total forecast opex	**95.37**	**95.36**	**98.51**	**103.18**	**106.60**	**499.01**
Preliminary decision						
Base year opex	73.70	73.70	73.70	73.70	73.70	**368.49**
Step changes	1.34	0.62	0.40	0.40	0.40	**3.16**
Escalation / rate of change	0.72	1.69	2.86	4.14	5.37	**14.79**
Category specific costs	0.66	0.69	0.73	0.76	0.79	**3.63**
Total forecast opex	**76.42**	**76.70**	**77.68**	**79.00**	**80.26**	**390.07**
JEN's submission						
Base year opex	81.82	81.82	81.82	81.82	81.82	**409.09**
Step changes	9.42	5.54	4.76	4.76	3.22	**27.71**
Escalation / rate of change	1.90	3.78	5.95	8.22	10.52	**30.37**
Category specific costs	0.67	0.70	0.75	0.78	0.81	**3.72**
Total forecast opex	**93.81**	**91.83**	**93.28**	**95.59**	**96.38**	**470.89**

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

24. Each component of the 'base, step, trend method' (including category specific forecasts) is discussed in the following sections.

2.1 SERVICE RECLASSIFICATION

2.1.1 JEN'S APRIL 2015 PROPOSAL

25. In our April 2015 proposal, we treated supply abolishment costs (up to 100 amps) as distribution services consistent with the final F&A paper.[18] In addition, given that the economic regulation of metering services under the AMI Order in Council ends on 31 December 2015, we reclassified certain network systems and customer support[19] activities previously recoverable under the AMI Order in Council to distribution services on the basis that:

- They are a necessary component of our distribution services in the 2016 regulatory period which JEN will need to incur irrespective of whether it is a provider of metering services
- They were always activities required for providing standard control distribution services, but had temporarily been recoverable under the AMI Order In Council because during the AMI rollout period their level was affected by the AMI deployment obligation.

26. Table 2–3 sets out our forecast portion of network systems and customer support costs (AMI Order in Council related in the 2011-2015 regulatory period) and supply abolishment (up to 100 amps) that we reclassified as distribution services in our April 2015 proposal, how that compares with the preliminary decision and our opex forecast in this submission.

Table 2–3: Service reclassification to distribution services ($2015, $millions)

Service reclassification	2016	2017	2018	2019	2020	Total
Metering	11.42	11.76	12.14	12.58	12.99	**60.89**
Supply abolishment	0.57	0.58	0.60	0.62	0.64	**3.01**
April 2015 proposal	**11.99**	**12.35**	**12.75**	**13.19**	**13.63**	**63.90**
Metering	-	-	-	-	-	**-**
Supply abolishment	0.55	0.55	0.56	0.57	0.58	**2.82**
Preliminary decision	**0.55**	**0.55**	**0.56**	**0.57**	**0.58**	**2.82**
Metering	8.86	9.06	9.29	9.53	9.77	**46.52**
Supply abolishment	0.55	0.56	0.58	0.59	0.61	**2.89**
JEN's submission	**9.41**	**9.62**	**9.87**	**10.12**	**10.38**	**49.41**

(1) The figures includes real cost escalation.

27. Our AMI Order in Council network systems and customer support and supply abolishment costs are included in our opex forecasting model set out in Attachment 8-3 of this submission.

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

19 These reclassified activities mainly comprise network systems IT staff costs for running the: connection point management system, data reporting, business to market gateway, and a share of the operations of the meter data management system and meter network management system associated with network billing. They also include lesser amounts for customer support, network billing, and reporting and finance. Attachment 9-1, Table 3-4 explains these activities and the basis of their cost attribution.

2.1.2 PRELIMINARY DECISION

28. In its preliminary decision, the AER endorsed its approach set out in its F&A paper and as submitted by JEN in its April 2015 proposal to reclassify supply abolishment as distribution services.[20]

29. The preliminary decision did not accept our proposal to classify some network systems and customer support costs as distribution services.[21] In doing so, the preliminary decision did not include $60.9m ($2015, escalated) of opex associated with reclassified network systems IT and customer support expenditure in its alternative opex forecast for distribution services. Instead, the preliminary decision treated the costs as part of alternative control metering services.

30. The preliminary decision also stated that each of the Victorian service providers have taken a different approach to how costs formerly recoverable under the AMI Order in Council should be allocated across distribution services and metering services. The AER considers a consistent approach across Victorian service providers is preferable to the allocation of costs that were previously regulated under the AMI Order in Council.[22]

31. Finally, the preliminary decision notes that the AER is obliged under the NER to develop a distribution ring fencing guideline by 1 December 2016 and that it expects in developing this guideline it will consider any cost allocation issues relating to metering costs.[23] Therefore, its preferred approach is to allocate all costs formerly regulated under the AMI Order in Council to alternative control services, which the AER believes will promote transparency around AMI trends and distribution services.

2.1.3 JEN'S RESPONSE AND THIS SUBMISSION

32. This submission maintains and builds on JEN's April 2015 proposal on service reclassification.

33. JEN welcomes the preliminary decision to reclassify supply abolishment as distribution services, which we have maintained in this submission, however, we do not agree with the preliminary decision approach to reclassify AMI Order in Council cost as metering services, We consider that the preliminary decisions has not adequately addressed the following issues when coming to a conclusion:

- The preliminary decision view on some network systems IT and customer support cost reclassification does not promote the Optimal NEO Position, and is inconsistent with the requirements of the NER. It is not appropriate to rely on future regulation (in the form of future distribution ring-fencing guidelines) to resolve cost classification issues faced now. The decision should be made under the regulatory framework as in force at the time of the preliminary decision
- The submitted reclassification will positively influence metering competition—which will take effect from 1 December 2017—and will in fact lead to more efficient outcomes by supporting allocative efficiency in the supply and use of metering services
- The preliminary decision fails to take account of the fact that the AMI Order in Council was a legislative instrument that temporarily distorted the classification of costs that would otherwise have been classified to distribution services if assessed under the NER
- The preliminary decision is internally inconsistent, in that it has provided for the recovery of some capex from distribution services, but not the opex that supports that capex.

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[20] AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 7 – Operating expenditure October 2015*, p 7-40

[21] Ibid, p 7-23 and section A5

[22] Ibid, p 7-40

[23] AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 7 – Operating expenditure October 2015*, p 7-40

34. JEN also notes that it is not necessary to have a standard approach to allocation of costs that were previously recoverable under the AMI Order in Council. It is not a rule requirement to do so. This is supported by a separate AER-approved cost allocation methodology (**CAM**) for each business rather than having a common allocation, and the fact that each distribution business uses different systems to operate its business, hence incurring different costs.

35. Section 5.1 of Attachment 9-1 to this submission provides a more comprehensive explanation of these issues.

36. Should the AER retain its preliminary decision in the substitute decision, then to ensure the incentive framework applying over the 2016 regulatory period is consistently applied, we request any costs reallocated from alterative control services to our distribution services within the period be excluded from the operation of the EBSS. This would be necessary to ensure that JEN is not penalised unfairly due to application of the yet to be determined distribution ring fencing guideline. This is discussed further in Attachment 3-1.

3. KEY INPUTS AND ASSUMPTIONS

37. The NER require us to set out the key variables and assumptions used in developing our forecast opex, and the methods used to develop these forecasts.[24] This section describes the key inputs and assumptions underlying our opex forecast, including the basis of the specific forecasts, and substantiates these inputs and assumptions.

38. In developing its alternative estimate of JEN's forecast opex for the 2016 regulatory period, the preliminary decision applied the 'base, step and trend' approach. JEN's opex forecast for the 2016 regulatory period largely mirrors this approach. In this submission each of the component part of the AER's 'base, step and trend' are discussed in turn, whether the preliminary decision agreed with JEN's assumption/approach or substituted its own view, and JEN's subsequent opex forecast for this submission.

3.1 ESTABLISHING THE EFFICIENT BASE YEAR

3.1.1 JEN'S APRIL 2015 PROPOSAL

39. In Attachment 8-2 of our April 2015 proposal, we proposed 2014 as our base year and demonstrated that it was efficient through comparable productivity performances and the AER's most recent annual benchmarking report (see section 2.1.1.2 of our April 2015 proposal).

3.1.2 PRELIMINARY DECISION

40. We welcome that the AER's benchmarking report which indicates that we are operating relatively efficiently when compared to other service providers in the NEM, this means that our revealed opex for 2014 is a reasonable starting point for determining our opex forecast.[25]

3.1.3 JEN'S RESPONSE AND THIS SUBMISSION

41. We note that the AER's 2015 benchmarking analysis is consistent with its 2014 analysis, noting that the gap between JEN and the next most efficient service provider has narrowed significantly.[26] Therefore, it is reasonable to assume that JEN is operating relatively efficiently when compared to other service providers in the NEM. Our revealed opex for 2014 continues to be a reasonable starting point for determining our opex forecast.

42. Accordingly, we maintain 2014 as our base year opex in this submission.

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24 NER Cl S6.1.2(3)

25 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 7 – Operating expenditure October 2015*, p 7-23

26 Table 1 on page 9 of AER's annual benchmarking report (2015) highlights that the industry faced declining productivity, but suggests JEN's drop in productivity (0.8%) is not as pronounced as SA Power Networks (4.3%)

3.2 ADJUSTING THE EFFICIENT BASE YEAR

43. Table 3–1 sets out JEN's April 2015 proposal and submission adjusted base year opex, compared with the efficient adjusted base year opex in the preliminary decision.[27]

Table 3–1: JEN's base year opex and adjustments ($2015, $millions)

	April 2015 proposal	Preliminary decision	This submission
Reported 2014 opex	74.85	74.83	74.28
Remove movement in provisions		(0.01)	(0.01)
Remove non-recurrent costs:			
• Earth testing in non CMEN areas	(0.21)		
• Public lighting switch removal	0.74		
• Electricity distribution price review (**EDPR**)	(2.15)		
• Remove loss on scrapping of assets	(0.40)	(0.40)	(0.40)
Remove self-insurance	(0.39)		
Remove GSL payments	(0.07)	(0.07)	(0.07)
Remove demand management incentive allowance (**DMIA**) expenditure	(0.07)	(0.07)	(0.07)
Adjusted 2014 opex	**72.30**	**74.28**	**73.73**
2015 increment	1.36	(1.12)	(1.11)
Estimated 2015 opex	**73.66**	**73.15**	**72.62**
Service reclassification adjustment	11.69	0.54	9.20
Estimated 2015 opex (for trending)	**85.35**	**73.70**	**81.82**

(1) The reported 2014 opex differs across the three cases. The preliminary decision applied a different Consumer Price Index (**CPI**) index (unlagged Dec to Dec quarter) relative to JEN's April 2015 proposal (lagged Sep to Sep quarter). We have adopted the preliminary decision CPI index in this submission, but updated the 2015 inflation rate to 1.75% (compared to the 2.50% in the preliminary decision) based on the RBA's statement on monetary policy (Nov 15) on page 67.

(2) JEN's April 2015 proposal estimated the 2015 opex forecast by applying the proposed opex rate of change to the adjusted base year. The preliminary decision substituted this estimate by taking into account the operation of the EBSS, where the last year of the current regulatory period (2015) is estimated so that the incremental gain/penalty under the EBSS for that year is nil. JEN has applied this method in this submission.

(3) This submission reclassifies both some metering services opex and supply abolishment costs as distribution services, however, we refine our cost allocation based on AER's comments in its preliminary decision.

3.2.1 JEN'S APRIL 2015 PROPOSAL

44. In our April 2015 proposal we:

- Adjusted our base year by $2.0m ($2015) for four non-recurrent costs (section 2.2 of Attachment 8-2), which included earth testing in non CMEN areas, public lighting switch removal, electricity distribution price review costs and losses on scrapping of assets

[27] Ibid, table A.1

- Removed from our base year categories of costs where the base year is not representative (category specific forecasts). The categories of costs removed were for demand side management (**DMIA**) and GSL payments, and we adopted a ‘zero-based’ method to develop our category specific forecasts (see section 2.3 of Attachment 8-2 of our April 2015 proposal)
- As noted in section 2.1 of this submission, we adjusted our base year by $11.5m ($2015) for the forecast portion of some metering services opex and supply abolishment costs reclassified to distribution services.

45. In relation to EDPR costs, JEN proposed a step change to account for them being removed from the base year (see section 3.4 of this submission).

3.2.2 PRELIMINARY DECISION

46. In the preliminary decision,[28] JEN’s 2014 base year opex was adjusted as follows:

- Removed opex movements in provisions
- Only approved loss on scrapping of assets as a non-recurrent cost given they reflect costs for accounting purposes only and not an outlay of funds (for the EDPR costs, the preliminary decision disallowed JEN’s proposed step change but did not adjust JEN’s 2014 base year opex for costs incurred in 2014)
- Agreed with JEN that DMIA and GSL payments costs are not representative in the base year and therefore should be removed from our base year
- Applied the EBSS method for estimating the final year expenditure (2015), as per its Expenditure Forecast Assessment Guideline for electricity distribution
- Agreed to reclassify $0.5m ($2015) of supply abolishment as distribution services but rejected JEN’s proposal of $11.5m ($2015) for reclassification of some metering services opex.

47. In assessing adjustments to JEN’s base year opex, the preliminary decision focused on total opex and not particular categories or projects. The preliminary decision asserted that a granular focus on cost categories is not likely to lead to a better forecast of total opex.[29]

3.2.3 JEN’S RESPONSE AND THIS SUBMISSION

48. JEN agrees with the adjustments from the preliminary decision to remove opex movement, loss on scrapping of asset (as a non-recurrent cost), DMIA and GSL payment costs (as being non representative from the base year opex).

49. In addition, JEN agrees with the preliminary decision’s method for estimating the 2015 opex forecast, taking into account the operation of the EBSS, where the last year of the current regulatory period (2015) is estimated so that the incremental gain/penalty under the EBSS for that year is nil. Therefore, JEN’s submission adopts the preliminary decision insofar as it adjusted this component.

50. JEN, however, maintains its position for the service reclassification. JEN’s submission adds back costs relating to:

- Supply abolishment

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28 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 7 – Operating expenditure October 2015*, Appendix A.

29 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 7 – Operating expenditure October 2015*, p 7-41

- Metering services costs, using a refined cost allocation that takes into account comments from its preliminary decision.

51. JEN's submission includes an estimate of the 2015 efficient base year opex of $81.8m ($2015).

3.3 TRENDING THE BASE YEAR

52. In applying its base, step, trend method, the preliminary decision adjusts base year opex for likely changes to opex (rate of change) over the 2016 regulatory period that result from:

- Price growth
- Output growth
- Productivity growth.

53. Table 3–2 sets out our forecast rate of change in our April 2015 proposal and submission compared with the preliminary decision for each year of the 2016 regulatory period.

Table 3–2: Forecast opex rate of change (per cent)

Forecast opex rate of change	2016	2017	2018	2019	2020	Average
April 2015 proposal	2.30%	2.64%	2.65%	2.53%	2.51%	**2.53%**
Preliminary decision	0.98%	1.30%	1.55%	1.67%	1.58%	**1.42%**
JEN's submission	2.32%	2.24%	2.54%	2.59%	2.55%	**2.45%**

54. Table 3–3 sets out our forecast dollar impact of the rate of change in opex in our April 2015 proposal and submission compared with the preliminary decision for each year of the 2016 regulatory period.

Table 3–3: Forecast rate of change in opex (2015, $millions)

Forecast real opex escalation	2016	2017	2018	2019	2020	Total
April 2015 proposal	1.99	4.34	6.79	9.25	11.72	**34.10**
Preliminary decision	0.72	1.69	2.86	4.14	5.37	**14.79**
JEN's submission	1.90	3.78	5.95	8.22	10.52	**30.37**

55. Each component of the rate of change is outlined below.

3.3.1 REAL PRICE GROWTH

56. Real price growth adjusts our base year opex for forecast real changes in key labour and materials costs.

3.3.1.1 JEN's April 2015 proposal

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

58. Table 3–4 sets out our forecast real price growth (per cent) in our April 2015 proposal and submission compared with the preliminary decision for each year of the 2016 regulatory period.

Table 3–4: Forecast real price growth (per cent)

Forecast real price growth	2016	2017	2018	2019	2020	Average
April 2015 proposal(1)	0.68%	1.02%	1.13%	1.03%	1.06%	**0.98%**
Preliminary decision	0.22%	0.50%	0.79%	0.92%	0.85%	**0.66%**
JEN's submission	0.22%	0.50%	0.79%	0.92%	0.85%	**0.66%**

3.3.1.2 Preliminary decision

59. The preliminary decision outlined forecast of price growth was on average 0.32% lower than JEN's forecast,[30] at 0.66% per year.

60. The following factors drive the difference between our April 2015 proposal forecast rate of change and the preliminary decision:

- To forecast labour price growth, we proposed the forecast change in the utilities Wage Price Index (**WPI**) as forecast by BIS Shrapnel (**BIS**) whereas the preliminary decision used the average of forecasts from Deloitte Access Economics (**DAE**) and BIS. In addition, JEN treated contracted services as a labour cost whereas the preliminary decision treated them as a mix of labour and non-labour costs.
- To forecast materials price growth, we utilised BIS's forecast material costs over the 2016 regulatory period, whereas the preliminary decision included materials costs in non-labour costs which it forecast to increase at the same rate as CPI.

61. The preliminary decision noted:[31]

- JEN provided no reasons why it used the forecast growth in a wage price index to forecast growth in the price of contracted services
- In previous analysis completed by the AER, it had found that DAE under-forecast utilities labour price growth at the national level and BIS over-forecast but by a greater margin.[32] The AER believes this is still the case and that DAE's forecasts will be the most accurate of both consultants' forecasts because they better reflect current labour market conditions. Therefore, the AER considers that its previous approach of applying the average of utilities WPI growth forecasts from DAE and BIS represents a realistic expectation of the cost inputs required to achieve the operating expenditure objectives
- Overall it was satisfied that the forecast growth in CPI reflects the increase in non-field contracted services required by an efficient service provider to meet the opex objectives
- It was not satisfied that a simple average of the forecast growth of the materials chosen by JEN reflects the price growth of materials prices affecting JEN because JEN does not purchase raw materials.

3.3.1.3 JEN's response and this submission

62. This submission replaces JEN's April 2015 proposal on real price growth. JEN has adopted the preliminary decision real price growth method (escalation and weights) and forecast in this submission.

30 Ibid, p 7-24.

31 Ibid, pp 7-49 to 7-53.

32 Ibid, p 7-52.

63. Further, whilst JEN believes that the preliminary decision labour rates and zero rate for materials costs are conservative, JEN has adopted them in this submission.

3.3.2 OUTPUT GROWTH

64. Output growth adjusts our base year opex for forecast increase in our operating and maintenance activities associated with growth in our customer base and our network's system physical capacity.

3.3.2.1 JEN's April 2015 proposal

65. We proposed output growth measures and weightings based on customer numbers (70.5%) and system physical capacity (29.5%). In our April 2015 proposal put forward an average output growth of 2.44% over the 2016 regulatory period.

66. Table 3–5 sets out our forecast output growth in our April 2015 proposal and this submission compared with the preliminary decision for each year of the 2016 regulatory period.

Table 3–5: Forecast output growth (per cent)

Forecast output growth	2016	2017	2018	2019	2020	Average
April 2015 proposal	2.57%	2.56%	2.39%	2.37%	2.28%	**2.44%**
Preliminary decision	0.75%	0.80%	0.75%	0.75%	0.73%	**0.76%**
JEN's submission	2.09%	1.74%	1.73%	1.66%	1.69%	**1.78%**

3.3.2.2 Preliminary decision

67. The forecast of output growth in the preliminary decision was on average 1.68% lower than JEN's forecast.[33]

68. The preliminary decision was not satisfied that JEN's proposed average annual output growth of 2.44% for the 2016 regulatory period reflects the increase in output an efficient service provider requires to meet its opex objectives.[34] In particular, the preliminary decision was not satisfied that JEN's:

- Output measures and forecasting method adopted to forecast output growth reflect a realistic expectation of the output growth JEN will experience
- Forecast of customer numbers (and maximum demand) reflect a realistic expectation of the demand forecast required to achieve the opex objectives.[35]

69. The preliminary decision noted that it considered JEN's calculation of system physical capacity based on the product of distribution transformer capacity and network line length does not produce a reasonable measure of output growth as it overstates output growth. The preliminary decision considered that circuit length and ratcheted maximum demand better reflects the outputs JEN will be required to deliver.[36]

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33 Ibid, p 7-24.

34 Ibid, p 7-53.

35 We note that the Preliminary Decision (AER, *Jemena distribution determination 2016 to 2020, Attachment 6 – Capital expenditure October 2015*) concluded that JEN's forecast maximum demand reflects a realistic expectation of the demand forecast.

36 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 7 – Operating expenditure October 2015*, pp 7-56 and 7-57.

70. Therefore, the preliminary decision:

- Determined JEN's output growth consistent with that adopted by Economic Insights' in its economic benchmarking report[37] and as set out in the Expenditure Forecast Assessment Guideline, comprising customer numbers (67.6%), circuit length (10.7%) and ratcheted maximum demand (21.7%)
- Used ratcheted maximum demand forecasts from Australian Energy Market Operator (**AEMO**)'s 2014 transmission connection point maximum demand forecasts[38] and its own forecast of customer numbers based on the annual average historical growth rate of 0.78% over 2007 to 2014.[39] We note that inclusion of 2006 customer numbers results in an annual average historical growth rate of 1.28%
- Used circuit length forecasts from our reset Regulatory Information Notice response (**reset RIN** or **EDPR RIN**).

71. In relation to ratcheted maximum demand forecasts the AER[40] subsequently advised JEN (in response to JEN questions) that it had used AEMO's 2015 forecasts and that given AEMO had forecast no growth in maximum demand the AER set ratcheted maximum demand for all years equal to AEMO's forecast for 2015.

3.3.2.3 JEN's response and this submission

72. JEN wishes to revise the position set out in section 2.3.3 of its April 2015 proposal on output growth, by replacing that section with this new section 3.3.2. In particular, JEN has:

- Adopted the preliminary decision output growth measures and weightings of customer numbers (67.6%), circuit length (10.7%) and ratcheted maximum demand (21.7%)
- Applied the following inputs in calculating the output growth:
  - **Customer number growth.** The AER tested and substituted the assumption of a one-to-one relationship between residential customer numbers and households implicit in our customer number forecast over the 2016 regulatory period.[41] In response Acil Allen reviewed the test undertaken by the AER[42] and concluded there are weaknesses in the rationale. JEN has reviewed ACIL Allen's assessment of the substitute approach[43] considers no compelling evidence to reject its April 2015 proposed method.
  - **Circuit length from our reset RIN.** We adopted the approach outlined in the preliminary decision.

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37 Ibid, pp 7-53 and 7-54. JEN had proposed the output growth measures and weightings of customer numbers (70.5%) and system physical capacity (29.5%).

38 AEMO, *AEMO Transmission connection point forecasting report for Victoria, forecasts developed by AEMO*, September 2014.

39 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 7 – Operating expenditure October 2015*, pp 7-54 to 7-55.

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

41 This forecast was developed by Acil Allen, see Attachment 3-3 of our April 2015 proposal.

42 See Attachment 7-8 to this submission.

43 See Attachment 7-7 to this submission.

- **Ratcheted demand forecast as set out in section 3 of Attachment 7-3 of this submission.** We based this forecast on the highest summer non-coincident 50POE weather corrected demand of 957.9 kVa in 2015.[44] The preliminary decision used AEMO's 2014 forecast for ratcheted peak demand forecast—a flat profile over the 2016 regulatory period—replacing JEN's April 2015 proposal forecast to estimate the opex rate of change. As anticipated in the preliminary decision, JEN has updated its demand forecast to take into account the most up-to-date information available and to better align our model with inputs used by the AEMO. We have considered AEMO's updated connection point forecasts.

73. Further detail is provided in Attachments 7-3 and 7-7 of this submission.

74. We note in the preliminary decision peak demand and customer number growth forecasts assumptions have been applied inconsistently, the preliminary decision sourced:

- Ratcheted demand from AEMO's 2015 forecasts for opex but adopted JEN's maximum demand forecast used to develop capex augmentation forecasts
- Residential customer growth from the historical data in the JEN's economic benchmarking RIN for opex but—in assessing JEN's customer connection capital expenditure forecast—the preliminary decision adopted JEN's forecast growth rates of residential and commercial / industrial connections.[45]

75. In principle, the various component parts should apply consistently in a regulatory submission to give effect to a robust regulatory decision. Therefore, when developing our opex and capital expenditure forecasts JEN submits a consistent approach to applying peak demand and customer number estimates to promote the Optimal NEO Positon. Further detail is included in JEN's response to the preliminary decision in Attachment 7-4 of this submission.

3.3.3 PRODUCTIVITY GROWTH

3.3.3.1 JEN's April 2015 proposal

76. JEN put forward a productivity growth of 0.89% per year for potential forecast economies of scale as the network is expected to grow.

77. Table 3–6 sets out our forecast productivity growth in our April 2015 proposal and submission compared with the preliminary decision for each year of the 2016 regulatory period.

Table 3–6: Forecast productivity growth (per cent)

Forecast productivity growth	2016	2017	2018	2019	2020	Average
April 2015 proposal	0.94%	0.93%	0.87%	0.86%	0.83%	**0.89%**
Preliminary decision	-	-	-	-	-	**-**
JEN's submission	-	-	-	-	-	**-**

44 If the AER uses the highest actual as the starting point (i.e. 1,016.7 kvA) then the forecast path should use the summer non-coincident 10POE weather corrected demand forecast.

45 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 6 – Capital expenditure October 2015*, pp 6-61 and 6-62.

3.3.3.2 Preliminary decision

78. The preliminary decision forecast a zero per cent productivity growth, which is on average 0.89% lower than JEN's forecast.[46]

79. The approach in the preliminary decision to the productivity measure is based on the AER's expectations of the productivity an efficient service provider in the distribution industry can achieve[47] to account for the shift in the productivity frontier.[48] We agree with the preliminary decision to not rely on historical productivity to set forecast productivity given this would incorporate the effect of past step changes and negatively impact on measured opex productivity.[49]

80. We welcome the preliminary decision adopting Economic Insights' recommendation to apply zero forecast productivity growth for efficient service providers.[50] Economic Insights' reason[51] for this approach was based on its:

- View that there is a reasonable prospect of opex productivity growth moving from negative productivity growth towards zero change in productivity in the next few years as energy use and maximum demand stabilise, given the excess capacity that will exist in the short to medium term and as the impact of abnormal one–off step changes recedes
- Concerns with the incentive effects of including negative opex partial productivity growth rates in the rate of change formula. Economic Insights thought that this would be akin to rewarding the networks for 'having previously overestimated future output growth and now entrenching productivity decline as the new norm. If the effects of step changes can be clearly identified, the forecast opex growth rates should be adjusted to net these effects out.

3.3.3.3 JEN's response and this submission

81. JEN has revised the position set out in section 2.3.4 of its April 2015 proposal on productivity growth by accepting the preliminary decision that zero productivity should apply for the 2016 regulatory period.

3.4 ADJUSTING FOR STEP CHANGES

82. Our submission forecast for opex step changes for distribution services shown in Table 3–7 is approximately $24.6m ($2015) more than the preliminary decision. The increase reflects our revised assessment on disallowed costs in the preliminary decision and additional costs to meet new obligations that have arisen since lodging our April 2015 proposal.

83. Attachment 8-2 of this submission provides further details on the individual step change items, their causation and the basis of their forecast.

[46] Ibid, p 7-24.

[47] Ibid, p 7-47.

[48] Ibid, p 7-48 and AER, *Better regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p 66.

[49] AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 7 – Operating expenditure October 2015*, p 7-59.

[50] Ibid, p 7-57.

[51] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November, p vii.

Table 3–7: Overview of our response to the preliminary decision on the step changes ($2015, $millions)

Step change	Our proposal	Preliminary decision	Our response to the preliminary decision	JEN's submission position	JEN's submission
Service inspection and testing program	6.15	-	✗	Same as April 2015 proposal	6.15
Overhead switch inspection	2.17	-	✓	No step change	-
Enclosed substation inspection and rectification	0.77	-	✗	Revised down from April 2015 proposal	0.56
Electricity Distribution Price Review	8.03	Included in base year	✓	Included in base year	-
Vegetation management[52]	15.89	-	≈	Revised down from July 2015 proposal	6.93
ESV code of practice changes	0.93	-	✓	No step change	-
Vulnerable customer initiative	1.01	-	✗	Same as April 2015 proposal	1.01
Customer engagement	0.93	Included in base year	✓	Included in base year	-
New technology trial: pole-top fire detection	1.38	-	✗	Same as April 2015 proposal	1.38
Demand management opex/capex trade-off	0.71	0.71	✓	Same as April 2015 proposal	0.71
Insurance premiums	0.17	-	✗	Same as April 2015 proposal	0.17
New tariffs	2.46	2.45	✓	Same as April 2015 proposal	2.45

[52] In response to the new amendments that commenced in Victoria on 28 June 2015, JEN revised its step change from $5.63m to $15.89m ($2015) in its *Submission to Jemena Electricity Network Ltd 216-20 regulatory proposal*, 13 July 2015, p 1.

Step change	Our proposal	Preliminary decision	Our response to the preliminary decision	JEN's submission position	JEN's submission
RIN reporting[53]	19.65	-	≈	Revised down from July 2015 proposal	5.88
Increased GSL obligations				New obligation	0.89
Power of choice				New obligation	0.88
Chapter 5A				New obligation	0.71

3.4.1 NEW OBLIGAITONS SINCE LODGING OUR APRIL 2015 PROPOSAL

84. Since lodging our April 2015 proposal a number of new obligations have arisen causing JEN to incur additional costs in the 2016 regulatory period that will need to be recovered:

- **Increase GSL obligations**—the ESC has placed new and amended obligation on the Victorian distribution network businesses resulting in an incremental step change for GSL payments (see section 15 of Attachment 8-2 of this submission for more detail). This step change is in addition to our category specific estimate for the baseline GSL payments that we have paid prior to the change in obligations (see section 3.5.1 below).
- **Power of Choice**—following the recommendations to the State and Federal governments by the AEMC's "Power of Choice review—giving consumers options in the way they use electricity"[54], the substantial reforms to the NEM will impose an additional obligation on JEN, resulting in increased opex. To recover the efficient costs for the increased obligation JEN proposes a further step change.
- **Chapter 5A connections**—the Victorian Government has tabled legislation[55] to implement elements of the NER chapter 5A connection framework replacing the ESC's Guideline 14 method for determining connection costs. JEN will incur increased opex to comply with the increased obligations stemming from this change.

3.5 ADDING CATEGORY SPECIFIC FORECASTS

85. JEN has added to its trended opex forecast, its category specific forecasts, namely:

- GSL payments (see section 3.5.1)
- Debt raising costs (see section 3.5.2)
- Demand side management (see section 3.5.3)

53 JEN proposed an additional $19.65m for RIN related expenses in complying with the AER's RIN requirements, Jemena, *Submission to its Regulatory proposal*, 13 July 2015, pages 3-6.

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

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

- Cost of equity (see section 3.5.4).

86. Further details on each of these are set out below.

3.5.1 GSL PAYMENTS

87. Table 3–8 sets out our forecast GSL payments in our April 2015 proposal and submission compared with the preliminary decision for each year of the 2016 regulatory period.

Table 3–8: Forecast GSL payments ($2015, $millions)

Forecast GSL payments	2016	2017	2018	2019	2020	Total
April 2015 proposal	0.07	0.07	0.07	0.07	0.07	**0.35**
Preliminary decision	0.05	0.05	0.05	0.05	0.05	**0.26**
JEN's submission	0.05	0.05	0.05	0.05	0.05	**0.26**

(1) JEN's submission excludes additional ESC obligations for GSL (treated as step change).

88. The preliminary decision agreed with JEN's GSL payments base year adjustment method and adopted the historical averaging approach calculation method to maintain consistency with how GSL payments have been forecast for previous regulatory control periods.[56]

89. This submission maintains and builds on JEN's April 2015 proposal on GSL payments.

90. JEN has forecast its GSL payments as follows:

- For our category specific component, we have applied the historical averaging approach method to calculating GSL payments consistent with the preliminary decision
- For the new GSL obligations we have calculated a step change (see section 3.4).

3.5.2 DEBT RAISING COSTS

91. Table 3–9 sets out our forecast debt raising costs in our April 2015 proposal and submission compared with the preliminary decision for each year of the 2016 regulatory period.

Table 3–9: Forecast debt raising costs ($2015, $millions)

Forecast Debt raising costs	2016	2017	2018	2019	2020	Total
April 2015 proposal	1.27	1.34	1.43	1.50	1.58	**7.13**
Preliminary decision	0.61	0.64	0.67	0.71	0.74	**3.37**
JEN's submission	0.62	0.65	0.70	0.73	0.76	**3.46**

92. The preliminary decision adopted its standard forecasting approach, which sets the forecast equal to the costs incurred by a benchmark firm as set out in its post-tax revenue model (**PTRM**).[57]

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[56] AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 7 – Operating expenditure October 2015*, pp 7-26 and 7-41.

[57] Ibid, p 7-27.

93. JEN accepts the preliminary decision method for calculating debt raising costs using the AER's PTRM (see Attachment 5-2 of this submission). We report these costs as 'Other' when including them in our opex forecast. Further detail on our forecast debt raising costs is included in Attachment 6-1 of this submission.

3.5.3 DEMAND SIDE MANAGEMENT

94. Table 3–8 sets out our forecast DMIA payments in our April 2015 proposal and submission compared with the preliminary decision for each year of the 2016 regulatory period.

Table 3–10: Forecast DMIA payments ($2015, $millions)

Forecast DMIA payments	2016	2017	2018	2019	2020	Total
April 2015 proposal	0.07	0.07	0.07	0.07	0.07	**0.33**
Preliminary decision	-	-	-	-	-	**-**
JEN's submission	-	-	-	-	-	**-**

(1) AER's PD and JEN's submission treat DMIA as a revenue adjustment, rather than opex allowances.

95. The preliminary decision agreed to adjust JEN's base year opex for DMIA payments, and provided for a $1m ($2015) allowance over the 2016 regulatory period.[58]

96. The preliminary decision has:

- Allowed a revenue increment of $0.2m ($2015) per annum arising from the application of its demand management incentive scheme (**DMIS**) (i.e. the 'Part A' allowance)
- Separately, allowed an opex step change of $0.7m ($2015) for two specific demand response opex programs.[59]

97. We understand that this approach is consistent with the NER as follows:

- Cl 6.4.3(a)(5), which states that the building blocks are to include the revenue increments or decrements (if any) for the year arising from the application of any demand management and embedded generation connection incentive scheme
- Cl 6.4.3(b)(5), which states that the increments/decrements referred to in (a)(5) are those that arise as a result of the an applicable demand management and embedded generation connection incentive scheme as referred to in clause 6.6.3
- Cl 6.6.3, which allows the AER to develop and publish a demand management and embedded generation connection incentive scheme. The AER refers to the DMIS that it published in April 2009 under this rule.

98. We accept the approach in the preliminary decision to treat DMIA as a revenue adjustment, rather than an opex item, and have adopted this approach in this submission (see Attachment 5-2 of this submission).

3.5.4 EQUITY RAISING COSTS

99. The preliminary decision includes equity raising costs within the capex forecast because these costs are only incurred once and are associated with funding the particular capital investments included within the capex

58 Ibid, p 7-41.

59 Ibid, section C.4.10 of Attachment 7, p 7-76.

forecast. The preliminary decision on JEN's forecast equity raising costs is based on the calculation included in its PTRM.[60]

100. We accept the method in the preliminary decision for calculating equity raising costs and has determined its forecast equity raising costs using the AER's PTRM (see Attachments 5-2 and 6-1 of this submission).

3.6 JEN'S SUBMISSION OPEX FORECAST

101. JEN's total opex forecast for the 2016 regulatory period is $470.9m ($2015) in this submission which achieves an Optimal NEO Position because it:

- Enables JEN to recover its efficient costs incurred in providing its distribution services
- Reasonably reflects the operating expenditure criteria[61] of:
  - The efficient costs of achieving the operating expenditure objectives
  - The costs that a prudent operator would require to achieve the operating expenditure objectives
  - A realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

60 AER, *Preliminary Decision, Jemena distribution determination 2016 to 2020, Attachment 3 − Rate of return, October 2015*, p 3-621.

61 The AEMC noted that '[t]hese criteria broadly reflect the NEO' - AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p 113.

4. COMPLIANCE WITH THE NER

102. We have prepared our total opex forecasts on a reasonable basis and developed them to comply with the operating expenditure objectives and operating expenditure criteria and to address the operating expenditure factors[62] along with other NER criteria for distribution services.

4.1 OPERATING EXPENDITURE OBJECTIVES

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

- Examining the proposed base year costs incurred in meeting our current service level and regulatory obligations (see section 3.1)
- Assessing the sufficiency of our current compliance with safety, regulatory and compliance obligations to identify step changes for corrective actions (see section 3.4)
- Assessing foreseeable new or changed obligations that will affect our operating activities and costs to identify step changes (see section 3.4)
- Incorporating escalation or de-escalation of our opex forecast for the rate of change including real price growth, output growth and productivity improvement (see section 3.3).

104. Table 4–1 summarises how we have complied with the operating expenditure objectives.

Table 4–1: Our compliance with the operating expenditure objectives

Operating expenditure objective	Rule	Our compliance
Meet or manage the expected demand for *standard control services*	6.5.6(a)(1)	We have trended our proposed base year opex to account for expected changes in output growth drivers of customer numbers and our network's system physical capacity (see section 3.3).
Comply with all applicable *regulatory obligations or requirements* associated with the provision of *standard control services*	6.5.6(a)(2)	We have assessed our current compliance (and associated base year costs), as well as identifying additional new and amended obligations that we expect to be in place over the 2016 regulatory period (see section 3.4 for our list of proposed step changes).
To the extent that there is no applicable regulatory obligation or requirement in relation to: - the quality, reliability and security of supply of *standard control services; or* - the reliability, safety and security of a *distribution system* through the *standard control services,* to the relevant extent:	6.5.6(a)(3)	We have proactively engaged with our consumers to first understand the level of service they value (see Attachment 4–1 of our April 2015 proposal), to assist the preparation of our comprehensive 7-year asset management plan (see Attachment 7–5 of our April 2015 proposal), and undertook a detailed service deliverability assessment (see Attachment 7–8 of our April 2015 proposal) to ensure we are in a position to meet these requirements.

62 NER cl. 6.5.6(a).

Operating expenditure objective	Rule	Our compliance
- maintain the quality, reliability and security of supply of *standard control services*; and - maintain the reliability and security of a *distribution system* through the supply of *standard control services*		
Maintain the reliability and security of a *distribution system* through the supply of *standard control services*	6.5.6(a)(4)	

(1) Italicised terms are as per the NER.

4.2 OPERATING EXPENDITURE FACTORS

105. The NER[63] set out the factors that the AER must have regards to when deciding whether or not to approve our opex forecast.

106. Table 4–2 summarises points we consider relevant to these factors.

Table 4–2: Our consideration of the operating expenditure factors

Operating expenditure factor	Rule	Our consideration
[deleted]	6.5.6(e)(1)	
[deleted]	6.5.6(e)(2)	
[deleted]	6.5.6(e)(3)	
The most recent *annual benchmarking report* that has been published under rule 6.27 and the benchmark opex by an efficient *Distribution Network Service Provider* over the *regulatory control period*	6.5.6(e)(4)	We fully support the use of benchmarking as useful cross-check information, but not in a deterministic way to set expenditure allowances. In our April 2015 proposal, we included the following relevant documents: • Attachment 8–4**,** which summarises our view on the role of benchmarking in assessing the opex efficiency, and • Attachment 8–5 (from Huegin), which assesses our historical opex performance over time. As noted in the overview and section 3.1, based on the AER's 2014 benchmarking report,[64] the preliminary decision found that JEN is operating relatively efficiently compared to other service providers in the NEM. The AER's 2015 benchmarking report[65] findings are consistent with its 2014 findings, noting that the gap between JEN and the next most efficient service provider has narrowed significantly.
The actual and expected opex of the *Distribution Network Service Provider* during any preceding *regulatory control*	6.5.6(e)(5)	We have included our historical expenditure performance for the 2011 regulatory period in Attachment 8–1 and section 2.1.1.1 of Attachment 8-2 of our April 2015 proposal. For

63 NER cl. 6.5.6(e).

64 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2014.

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

Operating expenditure factor	Rule	Our consideration
periods		periods prior to the 2011 regulatory period, we reported these in the economic and category analysis benchmarking RINs. In making its preliminary decision, the AER considered JEN's actual opex to form a view whether or not JEN's revealed expenditure is sufficiently efficient to rely on it as a basis for forecasting required opex in the 2016 regulatory period. The preliminary decision found that JEN's 2014 opex is a treasonable starting point for determining its opex forecast.
The extent to which the opex forecast includes expenditure to address the concerns of electricity consumers as identified by the *Distribution Network Service Provider* in the course of its engagement with electricity consumers	6.5.6(e)(5A)	We engaged proactively with our consumers before developing our opex forecast to first understand the level of service they value (see Attachment 4–1 of our April 2015 proposal).
The relative prices of operating and capital inputs (see section 4.4 of Attachment 7-1)	6.5.6(e)(6)	We rely on lifecycle management planning for each asset, which considers all strategies and options over the entire asset life from planning to disposal to deliver the lowest sustainable cost over the long run. Lifecycle management focuses on ensuring effectiveness and efficiency in maintenance (opex) and replacement (capex) of the network asserts based on reliability centred maintenance analysis and considers issues of safety, cost, risk and reliability. Additionally, we relied upon the same input real cost escalators for both opex and capex (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	6.5.6(e)(7)	We have considered these opportunities and have proposed: • An enhanced asset inspection program (opex) to complement the asset replacement strategy (capex) (see Attachment 2–1 of our April 2015 proposal), and • A step change in relation to demand management opex for capex trade-off (see Attachment 8–2), which the AER included in its alternative opex forecast for JEN in its preliminary decision.
Whether the opex forecast is consistent with any incentive schemes or schemes that apply to the *Distribution Network Service Provider* under clauses 6.5.8 or 6.6.2 to 6.6.4	6.5.6(e)(8)	Our private ownership—along with our consumers' expectations and the regulatory framework—provides us with strong incentives to act prudently and efficiently when assessing our expenditure. The two significant schemes that our opex forecast consider are the EBSS and the service target performance incentive scheme (**STPIS**), and we are committed to outperform our regulatory allowances over time. We: • Support both schemes and appreciate that the STPIS rewards any improvement in reliability and service levels (see Attachment 5–3 of our April 2015 proposal) • Note that our opex forecasts are required to maintain the reliability, quality and security of supply (as per NER clause 6.5.6(a)(3)), and not improve these. As a result,

Operating expenditure factor	Rule	Our consideration
		we did not propose any opex step changes to improve these standards.
The extent the opex 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	6.5.6(e)(9)	We have established outsourcing arrangements that reflect prudent commercial terms (see our response to section 19 of the EDPR RIN). The preliminary decision found that given the AER's assessment techniques focus on total opex efficiency it is less concerned whether arrangements do or do not reflect arm's length terms. As noted above, the AER found that JEN is operating relatively efficiently compared to other service providers in the NEM.
Whether the opex forecast includes an amount relating to a project that should more appropriately be included as a *contingent project* under clause 6.6A.1(b)	6.5.6(e)(9A)	Our submission opex forecast 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 contingent projects.
The extent the *Distribution Network Service Provider* has considered and made provision for, efficient and prudent non-*network* alternatives	6.5.6(e)(10)	We have considered whether there are any efficient non-network alternatives and proposed a step change in relation to demand management opex for capex trade-off (see Attachment 8–2). More detail is included in our response 21.2 of Schedule 1 of the EDPR RIN. The preliminary decision included JEN's demand management opex for capex trade-off in its alternative opex forecast for JEN and did not find this factor to be significant.
Any relevant final project assessment report (as defined in clause 5.10.2) *published* under clause 5.17.4(o), (p), or (s)	6.5.6(e)(11)	We do not consider this factor to be relevant to our opex forecast over the 2016 regulatory period.
Any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3 is an operating expenditure factor	6.5.6(e)(12)	The AER did not notify us of any other factor, not mentioned above, that it considers relevant. The preliminary decision did not identify any other opex factor that the AER considered relevant.

(1) Italicised terms are as per the NER.

4.3 FIXED AND VARIABLE COMPONENTS

107. In our building block proposal, we must outline our fixed and variable operating costs.[66] We set this out in section 4.3 of Attachment 8-2 of our April 2015 proposal.

[66] NER, Cl. S6.1.2(1)(iii).