Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review Regulatory Proposal

Revocation and substitution submission

Attachment 8-2 Operating expenditure step changes

Public

6 January 2016

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GLOSSARY

2015 Regulations	The Electricity Safety (Electric Line Clearance) Regulations 2015 (2015 Regulations) under the Electricity Safety Act 1998
Blue Book	Code of Practice for Electrical Safety
Bushfire regulations	The Electricity Safety Amendment (Bushfire Mitigation) Act 2014
July 2015 submission	JEN's 13 July 2015 submission to the Australian Energy Regulator
Optimal NEO Position	The position which contributes to the achievement of the NEO to the greatest degree and best promotes the long term interests of consumers of electricity.
Preliminary decision	The AER's preliminary decision released on 29 October 2015
Vegetation management obligations	Collectively, The Electricity Safety (Electric Line Clearance) Regulations 2015 (2015 Regulations) Under the Electricity Safety Act 1998 and the Electricity Safety Amendment (Bushfire Mitigation) Act 2014 (Bushfire Regulations)

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
CA	Category Analysis
capex	Capital Expenditure
CESS	Capital Expenditure Sharing Scheme
DEDJTR	Development, Jobs, Transport and Resources
DNSP	Distribution Network Service Provider's
DR	Demand Response
EB	Economic Benchmarking
EBSS	Efficiency Benefits Sharing Scheme
EDPR	Electricity Distribution Price Review
EFD	Early Fault Detection
ERP	Enterprise Resource Planning
ESC	Essential Services Commission
ESMS	Electrical Safety Management Scheme
ESV	Electricity Safe Victoria
FE	Footscray East
GSL	Guaranteed Service Level
HBRA	Hazardous Bushfire Risk Area
IJM	IJM Consulting Pty Ltd
JCARS	JEN's Compliance and Risk System
JEN	Jemena Electricity Networks (Vic) Ltd
LBRA	Low Bushfire Risk Area
MRO	AMI Mass Rollout
NEM	National Electricity Market
NER	National Electricity Rules
NH	North Heidelberg
NPC	Net Present Cost
NPV	Net Present Value
opex	Operating Expenditure
PB	Parsons Brinkerhoff
PoC	Power of Choice program
RIN	Regulatory Information Reporting

RIS	Regulatory Information Statement
SAPN	South Australian Power Networks
STPIS	Service Target Performance Incentive Scheme
TSS	Tariff Structure Statement
VCR	Value of Customer Reliability

OVERVIEW

Key messages

- In this submission Jemena Electricity Networks (Vic) Ltd (**JEN**) seeks operating expenditure (**opex**) step changes totalling $27.7m ($2015), less than half of the amount previously sought of $60.3m[1] ($2015)
- JEN agrees with the approach adopted in the preliminary decision for six of the opex step changes proposed in our April 2015 proposal, these include:
  - The capital expenditure (**capex**)/opex trade-off for demand management program
  - Additional costs to meet the new tariff obligations
  - Two step changes that the preliminary decision incorporated into the base year opex covering the regulatory proposal and customer engagement
  - Two step changes that were disallowed relating to the Electricity Safe Victoria (**ESV**) code of practice and overhead switch inspection program.
- However, JEN disagrees with the preliminary decision in its application of the regulatory framework by disallowing step changes for:
  - Enclosed substation inspection and rectification, regulatory information reporting (**RIN**) reporting requirements and vegetation management –JEN is not afforded a reasonable opportunity to recover the efficient costs[2] of new obligations
  - Service inspection and early detection program for pole-top fires – JEN is prevented from accessing incentives[3] to pursue operating and capital expenditure efficiencies
  - Our proposed vulnerable customer initiative – JEN attempted to best respond to consumer long term interests by offering a service they told us they wish to receive
  - Insurance premiums – Additional efficient costs that are not provided for in the base year opex.
- In addition to the opex step changes raised in our April 2015 proposal, JEN submits three additional opex step changes that have arisen after the preliminary decisions was made but will affect opex during the 2016 regulatory period, these include:
  - An increase in obligations relating to Guaranteed Service Level (**GSL**) standards (24 December 2015)
  - The Power of Choice program (**PoC**) (26 November 2015)
  - A requirement to adopt elements of the National Electricity Rules (**NER**) chapter 5A connection regime (8 December 2015).

[1] This amount include step change for increase Vegetation management obligations and RIN reporting obligation submitted on 13 July 2015.

[2] National Electricity Law (**NEL**), s. 7A(2).

[3] Ibid s. 7A(3).

1. The April 2015 proposal (together with any supporting material contained or referred to in the April 2015 proposal and 13 July submission[4]) is incorporated into, and forms part of this submission.

2. Step changes include increases or decreases in costs which may be due to new regulatory obligations, or changes in the operating environment that are outside our control. These also include changes in costs for initiatives that are sought by our customers or to capture opportunities to deliver efficiencies in future regulatory periods by changing opex activities in the current regulatory period (particularly capex trade-offs) that provide a longer term benefits.

3. JEN accepts the preliminary decision approach to six of the thirteen opex step changes proposed by JEN. This includes:

    - Overhead switch inspection – the preliminary decision considered these costs were an internal business decision to be absorbed in the opex allowance
    - Electricity Distribution Price Review – the preliminary decision included these costs in the base year opex
    - ESV code of practice changes – the preliminary decision considered these costs as a business as usual expense and were uncertain
    - Customer engagement – the preliminary decision included these costs in the base year opex
    - Demand management opex/capex trade-off – the preliminary decision accepted these costs resulted from a capex trade off
    - New Tariffs – the preliminary decision accepted these costs are associated with a new obligation – we have considered the step change in the context of the Victorian Government's policy direction for demand tariffs for residential and small business customers to be opt-in.

4. However, JEN does not agree with the treatment of the remaining seven opex step changes. This includes:

    - Service inspection and testing program – the preliminary decision did not allow an opex step change because the cost was not related to a new obligation
    - Enclosed substation inspection and rectification – the preliminary decision did not allow an opex step change because the cost was not related to a new obligation
    - Vegetation management – the preliminary decision did not allow an opex step change because it considered the forecast cost was too high
    - Vulnerable customer initiative – the preliminary decision did not allow an opex step change because the ESC is undertaking a review that the Australian Energy Regulator (**AER**) expects will inform the role of distribution service providers in providing assistance
    - Pole-top fire detection – the preliminary decision did not allow an opex step change because the benefits do not outweigh the costs
    - Insurance premiums – the preliminary decision did not allow an opex step change because the immaterial amount can be funded within the opex allowance
    - RIN reporting – the preliminary decision did not allow an opex step change because it considered the forecast cost was too high.

[4] JEN, *Submission to Jemena Electricity Network Ltd 2016-20 regulatory proposal,* 13 July 2015 (**13 July 2015 submission**)

5. Notably, the preliminary decision acknowledged the change in regulatory obligations for Vegetation management and RIN reporting may give rise to a justifiable step change. JEN has provided additional information to support the magnitude of the forecast opex step change.

6. In addition, JEN has included three additional step changes in this submission to reflect the additional efficient costs not included in the base year opex for new obligations relating to:

- Increased GSL obligations
- Power of Choice
- Adoption of elements of NER Chapter 5A for connecting customers.

7. JEN has included information in this submission to support these additional efficient costs of meeting new or increased obligations.

8. In this submission, we have added step changes to our opex forecast (See Attachment 8-1 of this submission for further details). Table OV–1 sets out our revised proposed step changes compared with the preliminary decision and our April 2015 proposal. These costs reflect forecast prudent and efficient opex not captured by the base year opex. Insufficient funding for these step changes will deny us a reasonable opportunity to recover our efficient costs.

Table OV–1: Overview of our response to AER preliminary decision on step changes

Proposed step change	April 2015 proposal	Preliminary decision	Our response to preliminary decision	This submission	Step change submission ($)
Service inspection and testing program	$6.15m	$0m	✗	Same as April 2015 proposal	$6.15m
Overhead switch inspection	$2.17m	$0m	✓	No step change	$0m
Enclosed substation inspection and rectification	$0.77m	$0m	✗	Revised down	$0.56m
Electricity Distribution Price Review	$8.03m	Included in base year opex	✓	Included in base year	$0.0m
Vegetation management	$15.89m	$0m	≈	Revised down	$6.93m
ESV code of practice changes	$0.93m	$0m	✓	No step change	$0m
Vulnerable customer initiative	$1.01m	$0m	✗	Same as April 2015 proposal	$1.01m
Customer engagement	$0.93m	Included in base year opex	✓	Included in base year	$0m
New technology trial: pole-top fire	$1.38m	$0m	✗	Same as April 2015	$1.38m

Proposed step change	April 2015 proposal	Preliminary decision	Our response to preliminary decision	This submission	Step change submission ($)
detection				proposal	
Demand management opex/capex trade-off	$0.71m	$0.71m	✓	Same as April 2015 proposal	$0.71m
[c-i-c]	[c-i-c]	[c-i-c]	[c-i-c] ✗	[c-i-c]	[c-i-c]
New tariffs	$2.46m	$2.45m	✓	Same as April 2015 proposal[5]	$2.45m
RIN reporting	$19.65m	$0m	≈	Revised down	$5.88m
Increased GSL obligations				New obligation	$0.89m
Power of Choice				New obligation	$0.88m
Adoption of Chapter 5A				New obligation	$0.71m

5 JEN's April 2016 proposal referred to $2.46m, the difference is due to rounding error.

1. SERVICE INSPECTION AND TESTING PROGRAM

1.1 JEN'S APRIL 2015 PROPOSAL

9. JEN proposed a step change in opex to reflect the costs of the inspection and testing of services in accordance with its regulatory obligations[6] to undertake testing at least every ten years. The cost of undertaking this activity is not included in the base year opex (2014) because, to date, this work has been undertaken most efficiently as part of the advanced metering infrastructure (**AMI**) meter rollout (i.e. inspection of services occurred while technicians were on site installing AMI meters). With the end of the AMI rollout, this has therefore become a step change in opex, which is not otherwise provided for under base year opex. The step change is $6.15m over the 2016 regulatory period.

10. The step change is required for JEN to continue to meet regulatory requirements. JEN must ensure that all overhead services have a 'neutral to earth' resistance of less than 1 ohm verified at least once every 10 years.[7] JEN has assumed[8] that 40% of services that will be replaced as part of the Service Rectification Program[9] will be replaced prior to requiring testing as part of this program, and as such, this number of services has been excluded from this step change. To comply with the regulation, all remaining services will need to be inspected and tested prior to 2020.

11. JEN outlined in section 3 of Attachment 8-6 of the April 2015 proposal the supporting information for this step change, including forecast cost and the basis for the forecast costs.

1.2 PRELIMINARY DECISION

12. The preliminary decision determined that JEN does not require an increase in opex for this program. The preliminary decision indicated that the increased opex is requested in response to an existing obligation (not a new obligation), that the base year opex reflects the costs of meeting existing obligations and variations in programs from year to year will offset each other.

1.3 JEN'S RESPONSE AND THIS SUBMISSION

13. We do not agree with the preliminary decision concerning the opex step change for service inspection and testing program. Our submission is that a step change in opex of $6.15m is required and promotes the **Optimal NEO Position**[10] because the new obligation increases the efficient cost of providing services, these costs are not included in the base year opex because we have been able to efficiently defer them until now, and the step change reflects the efficient costs of complying with this obligation.

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6 Electricity Safety (Management) Regulations 2009 [23 (11) and 27 (2)] and JEN, *Jemena Electricity Networks (Victoria) Ltd Safety Management Scheme –Synopsis [Document No. JEN PR 0900]*, 12 October 2011. (**JEN's ESMS**)

7 Electricity Safety (Management) Regulations 2009 [23 (11) and 27 (2)] and JEN's ESMS.

8 Based on the overlap that will occur between the schedules of the two programs.

9 The Service Rectification Program is a capital program that is replacing overhead services with the current standard and ensuring they meet required clearance heights (refer to Attachment 7-10).

10 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

1.3.1 INCREASE IN THE EFFICIENT COSTS OF PROVIDING DISTRIBUTION SERVICES

14. JEN accepts that the regulatory requirement in relation to service inspection has not changed, and it is not seeking recovery of additional costs associated with a change in regulatory requirements.

15. The step change principle is intended to give effect to the operating expenditure objectives, which include allowing JEN its efficient costs of complying with applicable regulatory obligations.[11] In this way, the base-step-trend approach put in place under the expenditure guidelines[12] is simply a tool to satisfy the objectives and expenditure criteria, and must be approached consistent with the need to meet that objective.

16. The step change approach must not be applied in a manner that undermines the operating expenditure objectives and criteria.[13]

17. In this case, during the AMI mass rollout (**MRO**) (September 2009 to June 2014), JEN was able to efficiently absorb the cost of this requirement because existing field technicians could undertake this work at the same time to installing AMI meters. With the completion of the MRO, JEN is no longer able to recover these costs in the same way. The change in circumstances that gives rise to the cost in the 2016 regulatory period is the end of the AMI rollout and associated obligations,[14] not a new regulatory requirement.

18. These efficient costs, which otherwise are clearly required to satisfy a regulatory requirement, are not otherwise being recovered. This submission therefore retains a step change of $6.15m.

1.3.2 INCREASE IN THE EFFICIENT UNIT COST OF PROVIDING DISTRIBUTION SERVICES

19. The costs associated with this obligation will not be included in the forecast opex for distribution services in the absence of an opex step change. During the MRO, JEN conducted installation of AMI meters and whilst installing a meter it is mandatory for the neutral integrity to be verified. Thus, JEN met the 10-year requirement to inspect and test services under the regulation during the installation of the AMI meters. The cost of testing services at the time of installation of a meter is negligible – the test takes an additional 3-5 mins. This step in the process of installing a meter is captured in the capital cost of installing the meter and is not separately recorded.

20. The approach adopted by JEN is consistent with the AER's expenditure guidelines, which holds that the AER will support an opex step change where this is an efficient means of replacing former capex.[15]

21. The costs of complying with this obligation are not included in the base year opex for distribution services. Although the AMI mass rollout was in the final stages of 2014, the cost was minor (i.e. the cost per service) relative to the cost of performing the service without the leverage benefit of performing the service in parallel with the MRO.

22. It would have been inefficient for JEN to complete a parallel program to inspect and test the services independent of the MRO. However, the efficiencies achieved in meeting this obligation during the mass rollout of meters are no longer available. Therefore, in the absence of providing an opex step change, JEN will not be able to recover the efficient costs of complying with this obligation as required for the provision of distribution services.

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[11] NER rule 6.5.5.

[12] AER, *Better Regulation, Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 22

[13] NER rule 6.2.8(c).

[14] AMI Order in Council, s. 14 and 14AA

[15] AER, *Better Regulation, Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p 35.

23. In order to meet the obligation, JEN must ensure that the services that were tested at the commencement of the AMI rollout in 2009[16] are tested and inspected within the 10-year period. It would be inefficient for JEN to match the sequence of the inspection and testing program to the particular meters rolled out in the AMI MRO program. This would require JEN to inspect and test services in exactly the same order as the meters were installed. Instead, JEN intends to geographically bundle the inspection and testing program so that all services in a geographical region are visited together to optimise the number of truck visits and crews required to undertake the work per service, and to aid in efficiency in visiting sites. The maintenance plans[17] for the program have been established on a geographical basis to achieve efficiencies with other geographical routine inspection programs.

24. The program planned for the 2016 regulatory period has been developed to ensure that the services that were inspected and tested at the commencement of the AMI MRO in 2009 are inspected and tested again within the 10-year obligation. Therefore, all services are planned to be inspected by 2019 to enable an efficient delivery of the program.

25. The last inspection and testing program undertaken by JEN to comply with this obligation occurred during the period 2002 to 2009. This program was delivered at a cost of $5.95m ($2015) at an average unit rate of $22.51 ($2015).

26. The average unit rate for the 2002-09 program varied from year to year due to fluctuations in work such as sites encountered where there is no access to test and inspect, and variance in the distance between sites. The average unit rate over the 2016 regulatory period is expected to be slightly higher due to a change in the scope of the work that now includes taking a photograph of defects. Taking photographs is more efficient than making incremental and on-going field visits to obtain information in discharging this new obligation.

27. Table 1–1 summarises the key assumptions in the program.

Table 1–1: Service inspection and testing program

Service inspection and testing program	Costs and volumes incurred per year
Services to be tested	272,405
40% of services in the Service Rectification Program will be replaced prior to the inspection/testing being required	13,600
Actual number of services to test	258,805
Required services per year	64,701
Unit cost per service ($2015)	$23.80
Cost per year ($2015)	$1.54m
Total cost of program for the 2016 regulatory period ($2015)	$6.15m

28. JEN's submission for the step change for the service inspection and testing program is presented in Table 1–2. As outlined earlier, the first test that was conducted as a part of the AMI MRO in 2009 must be re-tested and re-inspected within the 10-year period. JEN's April 2015 proposal had spread the costs of the program over the 2016-20 period, this profile has been amended in this submission to align to the program end date in 2019.

[16] Electricity Safety (Management) Regulations 2009 [23 (11) and 27 (2)] and JEN's ESMS

[17] IME1072 Service Inspection Manual.

29. The number of services that are required to be tested over the 2016 regulatory period remains the same. However, the number of services to be tested in each year has increased to 64,701 from 51,670 outlined in the April 2015 proposal to recognise that the testing is required to be completed by the end of 2019 consistent with the obligation. The cost per service tested remains $23.80 per service.

Table 1–2: Service inspection and testing program step change forecast ($2015, millions)

Step Change	2016	2017	2018	2019	2020	Total
Service inspection and testing program	1.54	1.54	1.54	1.54	-	6.15

30. JEN maintains that its submission promotes the Optimal NEO Position because it includes the additional efficient costs associated with complying with this obligation in the forecast opex for distribution services, as it enables JEN to recover the efficient cost of complying with its obligations. Further, completing of the service inspection and testing program over 2016 to 2019 will facilitate JEN meeting its regulatory requirement, benefit the customer by mitigating safety risks and maintain service levels and interruption of supply.

2. OVERHEAD SWITCH INSPECTION PROGRAM

2.1 JEN'S APRIL 2015 PROPOSAL

31. JEN proposed a step change in opex in its April 2015 proposal to reflect the change in approach for replacing air break overhead switches. JEN has around 1,000 air break switches installed and in service that were largely installed on the JEN network prior to 2000, with the majority of switches installed in the 1970's and 1980's; this age profile puts the majority of these assets at 25 years old or more.

32. Currently, switch failures are identified during day-to-day operations, typically when there is a need to operate the switch. In this instance, the switch is marked as defective and alternative arrangements are made to switch the network that avoids the use of the defective switch. This approach can increase the duration of customer interruptions or the number of customers interrupted (or both) for a given outage.

33. The change in approach is proposed to address the impact of a forecast growth in the failure of air break overhead switches because of increasing asset age that would otherwise lead to an increase in capital expenditure to replace failed switches. It is costlier to replace a failed switch under fault conditions than under a planned replacement program.

34. The step change in opex associated with the structured planned inspection program is for $0.43m per year ($2.17m over the 2016 regulatory period).

35. JEN outlined in section 4 of Attachment 8-6 of the April 2016 proposal the supporting information for this step change, including forecast cost and the basis for the forecast costs.

2.2 PRELIMINARY DECISION

36. The preliminary decision determined that JEN does not require an increase in opex for this program because this activity is not in response to a new obligation but rather is an internal business decision. The preliminary decision indicated that a step change may be approved if information is provided to support an efficient capex/opex trade-off.[18] However, the AER would expect that a cost benefit analysis should show that the program had a positive net present value (**NPV**) (the amount by which the capex savings exceed the increased opex) and demonstrate that a planned inspection program and subsequent replacement program would be more efficient than maintaining the "respond to failure" strategy.

2.3 JEN'S RESPONSE AND THIS SUBMISSION

37. We note the AER's position is to not accept the opex step change in the absence of a cost benefit analysis to show the program had a positive NPV for the amount by which capex savings exceed the increased opex. We have incorporated the AER's position into our proposal on the basis that JEN will continue to address the issue through its current approach of running the asset to failure and replacing them reactively.

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18 NER Cl. 6.5.7(e)(7).

3. ENCLOSED SUBSTATION INSPECTION AND RECTIFICATION

3.1 JEN'S APRIL 2015 PROPOSAL

38. JEN proposed a step change in opex to reflect a change in its regulatory obligations relating to section 7 of the Electricity Safety (Bushfire Mitigation) Regulations 2013. The change in this regulation has led to the requirement for JEN to undertake a routine proactive inspection of enclosed distribution substations every 37 months in the Hazardous Bushfire Risk Area (**HBRA**) and every 61 months in the Low Bushfire Risk Area (**LBRA**). However, JEN intends to undertake a program to target 36 months in HBRA and 48 months in LBRA to align the program with the inspection and rectification program for poles and lines. This will benefit the customer by bundling rectification works in a geographic area (such as a local street) as part of a single supply outage rather than the customer experiencing multiple interruptions to avoid deterioration in service compared to current levels. This will also enable JEN to efficiently plan and schedule works.

39. The enclosed substation inspection and rectification program is important in reinforcing public safety and mitigating against the risk of fire start by proactively identifying defects and prioritising their rectification.

40. JEN outlined in section 5 of Attachment 8-6 of the April 2015 proposal the supporting information for this step change, including forecast cost and the basis for the forecast costs.

3.2 PRELIMINARY DECISION

41. The preliminary decision determined that JEN does not require an increase in opex for this program. The preliminary decision recognised that there was a change in the regulatory obligation however; the preliminary decision determined that the change in regulation largely mirrored the position that has been in place since 2010 consistent with the Regulatory Information Statement (**RIS**) prepared for the ESV. On this basis, the preliminary decision determined that the new obligation does not impose a heavier burden on JEN. The preliminary decision also noted that other distribution network service providers did not propose a step change for this changed obligation.

42. In addition, the preliminary decision considered that two thirds of the forecast cost associated with rectification is already covered as part of 'business as usual' asset maintenance costs. The preliminary decision indicated that JEN did not outline how frequently it was inspecting and rectifying substations in hazardous bushfire risk areas prior to 2013 and that consumers may be paying double if rectification costs were added as a step change when these costs are already accounted for in the base year opex forecast. The preliminary decision stated that JEN had not demonstrated that there has been a material change in its legal obligations.

3.3 JEN'S RESPONSE AND THIS SUBMISSION

43. We do not agree with the preliminary decision on the step change for enclosed substation inspection and rectification. The preliminary decision was based on the view that there is no heavier burden, that providing for rectification costs would result in a double count of costs and that JEN had not demonstrated that there has been a material change in legal obligations. JEN does not agree with these reasons on the basis that:

- The new obligation requires JEN to increase the scope of its routine inspection program which has an impact on the efficient cost of providing distribution services

- The forecast opex step change is for only the consequential incremental rectification costs – not all rectification costs.

3.3.1 NO HEAVIER BURDEN

44. The new regulation does impose a heavier burden than previously in place and that without an opex step change would prevent JEN from recovering its efficient costs in meeting the regulatory requirement.

45. The previous regulations applied to poles and lines only. However, section 7(1)(i) now includes a requirement for a plan for inspection for all the parts of the network[19] which includes enclosed substations. JEN has not previously included inspection of enclosed substations because doing so would have exceeded the obligations and therefore been imprudent. The cost, therefore, of complying with the obligation are not included in the base year opex.

46. Introduction of the Electricity Safety (Bushfire Mitigation) Regulations 2013 requires that enclosed substations be inspected on a routine basis (at least every 37 or 61 months), which requires the introduction of a managed scheduled program of inspections. The opex step change is for the additional cost of including the inspection of the enclosed substations. The cost of including the inspections within the routine pole and line inspection program is less than undertaking a stand-alone inspection program.

47. Routine pole and line inspection in the LBRA on a 48-month inspection cycle has been adopted since the days prior to privatisation. It is proposed that inspection of enclosed distribution substations will be incorporated into this inspection cycle to maximise efficiency in planning and executing rectification work. If we inspect all assets in a particular geographical inspection zone on the same cycle, efficiencies can be achieved by packaging rectification work in that particular section of the network. As a result, customers will only be off supply for a single planned maintenance event (including rectification of substation) rather than experiencing multiple planned outages. If JEN inspects poles and lines in a certain geographical area (such as a street) on a 4-year cycle, and enclosed substations on a 5-year cycle, we will interrupt electricity supply to that street twice within 12 months, where rectification work is required and additional costs associated with site visits will be incurred.

48. In our April 2015 proposal, JEN forecast $0.77m for opex to be included in the forecast as a step change. The estimated opex step change was net of expenditure we expected to incur in the base year (2014). The expected expenditure was based on an assumption that 100 inspections would occur in 2014. However, the program was deferred and no inspections took place in 2014. It is not possible to defer inspections any longer because doing so would cause JEN would be in breach of its regulatory obligations.

49. Instead, costs associated with rectifications works from the inaugural 2012-13 program[20] were incurred in 2014. Therefore, the forecast opex step change has been reduced by the actual expenditure undertaken during 2014 associated with rectification work rather than the estimated inspection costs at the time of the April 2015 proposal. Further, the unit rate for rectification works and the number of substations to be inspected in future years has slightly changed. As a result, JEN is now proposing a net opex step change of $0.56m ($0.14m per year) as outlined in Table 3–1.

50. The preliminary decision indicated that JEN did not provide the number of inspections and rectifications in past years. Table 3–1 presents the actual number of inspections and the achieved unit rates for HBRA and LBRA for the period 2012 to 2014 and the forecast for the period 2016 to 2019.

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[19] Electricity Safety (Bushfire Mitigation) Regulations 2013, section 7(1)(i).

[20] JEN undertook a one off inspection program of enclosed substations during 2012 and 2013 that resulted in additional rectification work and expenditure in 2014 compared to the usual approach to reactively undertaking rectification work.

Table 3–1: Summary of inspections of enclosed substation over time

Inspections	2012	2013	2014	2015	2016	2017	2018	2019	2020
HBRA inspections	65	12	0	107	49	49	49	49	49
LBRA inspections	642	991	0	1137	474	474	474	474	474
Total inspections	**707**	**1,003**	**0**	**1,244**	**523**	**523**	**523**	**523**	**523**
Total number of enclosed substations	**1,916**	**1,972**	**2,015**	**2,067**	**2,131**	**2,194**	**2,258**	**2,323**	**2,388**
Inspection unit rate (average)	**$126.80**	**$126.80**	**-**	**$120.00**	**$120.00**	**$120.00**	**$120.00**	**$120.00**	**$120.00**

51. As can be seen in Table 3–1, there were no inspections in 2014 (the estimate provided in the April 2015 proposal was 100). However, the number of rectifications undertaken was higher than that estimated in the April 2015 proposal. The inspection program for 2015 planned to inspect an increased number compared to the ongoing program to bring the program back on schedule and align the inspections and rectification work with the pole and line inspection and rectification program in those geographical areas. Therefore, it is intended that all enclosed substations in HBRA areas will be inspected during the three-year period 2014-2016 and all enclosed substations in LBRA areas will be inspected during the four-year period 2014 to 2017.

52. Note that although the number of enclosed substations installed on the network is increasing, inspections in the 2016 regulatory period have remained flat as the substations installed in the period will not be required to be tested until later in the period, or the next regulatory period.

3.3.2 NO DOUBLE-COUNT OF RECTIFICATION COSTS

53. The rectification costs will increase as more substations are inspected and more rectification requirements identified. Previously these costs were only incurred when an issue was reported from the public or our crews.

54. Customers will not pay twice for rectification costs. The rectification costs associated with the customer initiated and ad-hoc rectification remain in the base year opex for asset maintenance. Only the rectification costs associated with the routine inspections that are included in the opex step change and presented in Table 3–2. It is assumed that rectification is required for 50% of the enclosed substations inspected – the number of substations requiring rectification as a result of the inaugural 2012-13 program was higher (approximately 70%), however less issues are expected to be identified given that the substations have previously been inspected[21].

55. Table 3–2 presents the number of historical and forecast rectifications and unit rates.

[21] This estimate is based on both engineering and field experience.

Table 3–2: Summary of rectification of enclosed substation over time

Rectification	2013	2014	2015	2016	2017	2018	2019
HBRA rectification	52	6	20	24	24	24	24
LBRA rectification	678	128	137	237	237	237	237
Total No. of rectification	**730**	**134**	**157**	**261**	**261**	**261**	**261**
Rectification unit rate	**$392**	**$392**	**$392**	**$392**	**$392**	**$392**	**$392**
Total expenditure on rectification ($2015, millions)	**$0.05m**	**$0.06**	**$0.1m**	**$0.10m**	**$0.10m**	**$0.10m**	**$0.10m**

56. Inspection commenced in late October 2012 and finished in 2013. The rectifications required—as a result of the inspections—were carried out during 2013, 2014 and 2015.

57. In the April 2015 proposal, JEN indicated a unit rate of $440 per substation for defect rectification. Since then, further rectification works have been completed and based on further experience and additional data JEN is now estimating a lower unit rate of $392 per substation to reflect the unit rates that have been achieved in recent years.

58. Once identified, an issue is prioritised and rectified within the timeframe outlined for the particular issue involved. JEN would not be compliant with its safety obligations if it identified an issue that could potentially result in a risk to public safety and it did not address it in the required timeframe.

3.3.3 NOT PROPOSED BY OTHER NETWORK SERVICE PROVIDERS

59. JEN is unable to comment on the asset management techniques of all distribution service providers or the reasons why other distribution service providers did not propose an increase in the efficient costs of providing distribution services as a result of the change in the obligation to inspect enclosed substations. The asset management practices of other distribution service providers may differ to JEN which will impact on the activities they have or have not undertaken in prior periods or will or will not undertake in future periods – and the efficient costs of these activities. JEN notes that the NER:

- Does not require the distribution service providers be aligned on their asset management approaches.
- Requires the AER to assess the total opex[22] for each distribution business and assessing proposed opex step changes where the efficient cost of providing services increases, for example when new obligations are imposed, is consistent with the AER's approach to assessing opex forecasts. This is supported by the AER's own claims for assessing opex in its preliminary decision[23].

22 NER, Cl 6.5.6.

23 AER, *Jemena Preliminary decision 2016-20, Attachment 7 - Operating expenditure*, October 2015, p 7-66.

- Requires the AER to assess efficiency of safety related expenditure against the obligations of each jurisdiction, for Victoria this requires a review against licence obligations and the safety management plans of each individual network service provider, not the Electrical Safety Management Scheme (**ESMS**) across each of the distribution businesses.

60. JEN notes that:

- Each distribution business has its own approach to managing costs and risks of maintaining and operating its network
- The scale of the network could play to the ability of a service provider to manage the costs across the network to smooth out expenditure; JEN, being a relatively small network, cannot efficiently manage costs in this way and must look to manage lumpy costs through this step change.

61. JEN's submission for the step change for the enclosed substation inspection and rectification program is presented in Table 3–3. The proposed inspections did not occur in 2014 due to unavailability of resources but rectification works were higher than estimated. As a result, rectification costs incurred in the 2014 base year opex has been removed from the forecast step change. Therefore, the forecast cost required as a step change has reduced compared to our April 2015 proposal.

Table 3–3: Enclosed substation inspection and rectification step change forecast ($2015, millions)

Enclosed substation inspection and rectification	2016	2017	2018	2019	2020	Total
Inspection program to meet new obligation	0.063	0.063	0.063	0.063	0.063	0.314
Rectification of defects	0.102	0.102	0.102	0.102	0.102	0.512
Less 2014 rectification expenditure	*0.053*	*0.053*	*0.053*	*0.053*	*0.053*	*0.262*
Total step change	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.56**

62. Our submission is that a step change of $0.56m is required to efficiently comply with the new obligation. We confirm that our proposal promotes the Optimal NEO Position because the costs of complying with this obligation have not been provided in the base year opex, and forecast costs reflect the costs incurred by a prudent and efficient network service operator.

63. The enclosed substation inspection and rectification program will address risks to public safety, supply reliability and potential fire starts by proactively identifying defects and prioritising their rectification. By aligning the program with the pole and line inspection in a particular geographical area of the network, there will be efficiencies in planning and scheduling the resultant rectification work and the customer will only experience one electricity supply outage, rather than multiple planned interruptions for a number of defects in their street.

4. REGULATORY PROPOSAL

4.1 JEN'S APRIL 2015 PROPOSAL

64. JEN proposed a step change in opex to reflect the forecast costs of the regulatory proposal process required every 5 years. This step change is consistent with the adjustment JEN proposed to the base year opex for the non-representative level of EDPR costs incurred in the 2014 base year opex. The total step change in opex is $8.03m. The amount varies each year to reflect the expected activities in each year.

65. JEN outlined in section 6 of Attachment 8-6 of the April 2015 proposal the supporting information for this step change, including forecast cost and the basis for the forecast costs.

4.2 PRELIMINARY DECISION

66. The preliminary decision did not include a category specific forecast for this program. Instead, the preliminary decision did not remove these costs from the base year opex. The preliminary decision indicated that this was because there are risks associated with adopting a hybrid of revealed costs and category-specific forecasting approaches and that to accept a category-specific forecast would be inconsistent with the AER's approach to the service inspection and testing step change.

4.3 JEN'S RESPONSE AND THIS SUBMISSION

67. We note that the preliminary decision position is to include the costs associated with the regulatory proposal process in the base year opex forecast to avoid incorporating category-specific forecasting approaches. JEN remains of the view that there are certain categories of opex where a category specific forecast will promote the Optimal NEO Position, particularly where the expenditure is lumpy and time based and would not prudently be incurred in the year adopted as the base year opex for establishing forecast opex.

68. JEN has incorporated the approach taken in the preliminary decision into our submission on the basis that it does not significantly change the outcome given the efficient costs forecast by JEN, the timing of efficient forecast costs and that at this time JEN does not forecast a penalty under the efficiency benefits sharing scheme (**EBSS**) for the next period.

69. Nevertheless, if the AER were to determine that no category specific approaches should be adopted on the basis that JEN has accepted the regulatory proposal and customer engagement costs in the base year opex, JEN maintains that it promotes the Optimal NEO Position to provide for category-specific forecast of costs where:

- A prudent and efficient network service provider would not incur the cost in the base year opex used for forecasting opex for the regulatory period; and
- A penalty under the EBSS would result.

5. VEGETATION MANAGEMENT

5.1 JEN'S APRIL 2015 PROPOSAL

70. In our April 2015 proposal and 13 July 2015 submission (**July 2015 submission**)[24] JEN proposed a step change for the additional costs it will incur in meeting its vegetation management obligations over the 2016 regulatory period due to the following legislative changes:

- The Electricity Safety (Electric Line Clearance) Regulations 2015 (**2015 Regulations**) under the Electricity Safety Act 1998
- The Electricity Safety Amendment (Bushfire Mitigation) Act 2014 (**Bushfire regulations**)

(referred to collectively as the **vegetation management obligations**).

71. To meet the altered vegetation management obligations, JEN initially proposed, in our April 2015 proposal, a step change of $5.63m ($2015). At the time of our April 2015 proposal the 2015 Regulations were in draft form only (the **exposure draft**). Accordingly JEN's proposal was based on the exposure draft and indications JEN had received from the Energy Safe Victoria (**ESV**) as to the likely scope of the final regulations.

72. The 2015 Regulations were finalised on 26 June 2015. The final regulations were not consistent with the position JEN expected based upon the exposure draft and JEN's interactions with the ESV. As a result, on 13 July 2015 JEN submitted[25] a revised step change for $15.89m ($2015) in the July 2015 submission.

73. Table 5–1 shows the breakdown of additional expenditure JEN expected to incur in July 2015, as a result of the vegetation management obligations. These costs were included in JEN's July 2015 submission

Table 5–1: July 2015 submission - revised vegetation management obligations step change proposal ($2015, millions)

	Step change forecast					
	2016	2017	2018	2019	2020	Total
Electricity Safety (Electric Line Clearance) Regulations 2015	3.16	3.16	3.16	3.16	3.16	15.80
Electricity Safety Amendment (Bushfire Mitigation) Act 2014	0.09	0.00	0.00	0.00	0.00	0.09
Total step change	**3.25**	**3.16**	**3.16**	**3.16**	**3.16**	**15.89**

74. Given the short time frame between when the 2015 Regulations were finalised (26 June 15) and the deadline to submit to the Electricity Distribution Price Review (**EDPR**) consultation process (13 July 15), JEN submitted a cost estimate based on the high level estimates JEN had prepared and submitted to the ESV[26] during its consultation on the Regulatory Impact Statement.[27]

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

25 Ibid, p 3.

26 Jemena Ltd, *Jemena comments on the proposed Electricity Safety (Electric Line Clearance) Regulations 2015,* 13 January 2015

27 ESV, *Regulatory Impact Statement, Electricity Safety (Electric Line Clearance) Regulations 2015,* September 2014

5.2 PRELIMINARY DECISION

75. The preliminary decision recognised that JEN's vegetation management step change arose as a result of new regulatory obligations that may give rise to a justifiable step change[28] and that there was potential for cost increases associated with the 2015 Regulations.[29]

76. However, the preliminary decision did not approve a step change to comply with the vegetation management obligations. This was because the AER considered the change in costs arising from the 2015 Regulations were uncertain for the following reasons:

- Based upon feedback it had received from the ESV, the AER did not consider JEN's estimated costs reflected the change in compliance costs arising from the 2015 Regulations as those costs were not consistent with the manner in which the AER understood the ESV will administer the 2015 Regulations[30], and
- The AER considered that there was uncertainty around the net impact of changes in the 2015 Regulations due to uncertainty around the decrease in costs arising from the reintroduction of exceptions for structural branches in relation to both insulated and uninsulated electric lines and the increase in costs from the enhanced notification requirements and compliance with pruning of amenity trees.[31]

77. The preliminary decision did not address the costs associated with the Bushfire Regulations.

78. The preliminary decision appeared to be interim in nature in that it indicated that:

- ESV had foreshadowed that it would provide more detailed guidance to all Victorian distribution businesses to ensure that they understood the manner in which the ESV will administer the 2015 Regulations[32]
- The AER expected JEN's revised proposal to reflect the manner in which the ESV would administer the regulations and clearly discuss any cost savings arising from the reinstatement of exceptions for maintenance of structural branches within the clearance space as well as cost increases for new notification and consultation requirements,[33] and
- The AER's final decision on the step change would take into account all of the above factors in coming up with the overall change in costs to comply with the regulatory changes.[34]

79. In the letter dated 20 November 2015, JEN sought guidance from the AER as to the assumptions and material it relied upon (including any costings and calculations) in coming to its preliminary decision.[35] In the letter dated 24 November 2015 the AER responded that it had provided all relevant materials it had relied upon as part of the preliminary decision.[36] Should the AER seek to rely upon any material not included in its preliminary decision in coming to its substituted decision, JEN considers as a matter of procedural fairness, that it should be provided with an opportunity to comment on that material before any substituted decision is made.

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28 AER, *Jemena Preliminary decision 2016-20, Attachment 7 – Operating expenditure*, 29 October, 2015, p 7-64

29 Ibid, p 7-73

30 Ibid, p 7-72

31 Ibid, p 7-72 and 7-73

32 Ibid, p 7-72

33 Ibid, p 7-73

34 Ibid, p.7-73

35 Letter titled *Vegetation Management operating expenditure step change,* from Robert McMillan (JEN) to Chris Pattas (AER), 20 November 2015

36 Letter titled *Jemena 2016 Electricity Distribution Price Review preliminary decision -vegetation Management operating expenditure step change,* from Chris Pattas (AER) to Robert McMillan (JEN), 24 November 2015

5.3 JEN'S RESPONSE AND THIS SUBMISSION

80. Since July 2015, and in particular, in response to the preliminary decision, JEN has:

- Reviewed the requirements necessary to comply with the vegetation management obligations with a view to identifying the most efficient way to respond to those new obligations
- Consulted with ESV to better understand how the ESV will administer the 2015 Regulations and to identify the basis of any differences of interpretation of the 2015 Regulations between ESV and JEN
- Sought advice from persons involved in auditing JEN's compliance to the applicable regulations relating to vegetation management and from the contractors who undertake JEN's vegetation management to determine if there is likely to be any decrease in costs as a result of the reintroduction in the 2015 Regulations of the exceptions for structural limbs
- Sought legal advice from Susan Brennan SC[37] to assist us to interpret the 2015 Regulations and to understand the scope of activities that are required by law under the new regulations.

81. Based on these activities and, with a revised understanding of our vegetation management obligations, JEN has amended our forecast step change to $6.93m ($2015).

82. JEN considers that this step change:

- Satisfies the AER's assessment approach because:
  - The amounts included in the step change are not compensated via base opex or accounted for by applying an annual rate of change escalation
  - The costs claimed are costs which a prudent and efficient service provider would need to meet the new obligations imposed by the vegetation management obligations
- Is necessary to satisfy the operating expenditure criteria, to promote the operating expenditure objectives, to ensure that JEN is provided the opportunity to recover at least its efficient costs to comply with the new vegetation management obligations and to attain the Optimal NEO Position.

83. The sections below outline our forecast costs to comply with the vegetation management obligations and respond to the issues raised in the preliminary decision, (including by providing evidence that JEN will not receive any reduction in costs associated with the re-introduction of exceptions relating to maintaining structural branches).

5.3.1 THE MANNER IN WHICH ESV INTEND TO ADMINISTER THE 2015 REGULATIONS

84. In the preliminary determination the AER indicated JEN should revise our proposal following further guidance from ESV as to the manner in which ESV would administer "*its rules*".[38]

85. Following the preliminary decision, JEN met with ESV on 13 November 2015 to seek guidance on the manner in which the ESV intends to administer the vegetation management obligations and to discuss the three key areas of change within the 2015 Regulations which impose incremental material costs upon JEN. These include:

- Amenity tree management standards required to comply with Australian Standard 4373

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[37] See Attachment 8-6 to this submission.

[38] AER, *Jemena Preliminary decision 2016-20, Attachment 7 – Operating expenditure*, 29 October, 2015, p 7-73

- Enhanced notification and consultation provisions
- [c-i-c]

86. At the meeting, ESV undertook to provide JEN with written guidance on these three key issues—and in response to a separate written request from JEN[39] (See Attachment 8-7), to provide their views on how changes in provisions relating to maintenance of structural branches might affect JEN's vegetation management practices (this issue is discussed separately in section 5.3.7 of this attachment). JEN received ESV's written advice responding to these issues on 27 November 2015[40] and 30 November 2015.[41] These letters are submitted with this proposal at Attachment 8-9 and Attachment 8-8 respectively.

87. The advice JEN received from ESV provides some indication of how the ESV intended to interpret the 2015 Regulations and the manner in which ESV might seek to administer the 2015 Regulations. However when these views were compared to the interpretation given to the same regulations by Susan Brennan SC there were some material differences.

88. In seeking to resolve these differences JEN sought advice from Susan Brennan SC as to JEN's ability to rely upon ESV's views and ESV's interpretation of the 2015 Regulations. In responding to this query Susan Brennan SC advised:

- It was not merely the ESV who may refer to and seek to enforce the provisions of the 2015 Regulations.[42] There are numerous other stakeholders who could seek to enforce compliance with the 2015 Regulations including, but are not limited to, individuals, businesses, Councils and Government—all of whom could bring an action against JEN for failing to comply with the 2015 Regulations. ESV also noted this point in the RIS prepared in September 2014 assessing the impact of the 2015 Regulations:

> *"The electricity assets addressed via the existing and proposed regulations are privately owned. Asset owners have significant incentives to manage their assets in ways that reduce the likelihood of their contributing to bushfire ignition. These incentives derive in part from the fact that bushfires may cause significant damage to these assets, implying substantial costs to asset owners. In addition, where fires are caused by these assets, those who incur losses as a consequence will potentially take legal actions to recover those losses from the electricity asset owners. Indeed, several actions of this kind have been concluded since the Black Saturday fires, with significant payments being made by electricity asset owners. Thirdly, electricity asset owners may suffer due to negative community perceptions if it is believed that the ignition of fires resulted from a failure to maintain those assets adequately so as to prevent bushfire ignition. Finally, where interference between power lines and vegetation causes supply outages, asset owners both suffer revenue losses due to power not supplied and may risk action being taken against them by businesses that suffer consequent losses in some circumstances".*[43]

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[39] Letter from Robert McMillan (JEN) to Paul Fearon (ESV), *Guidance on compliance and audit under Electricity Safety (Electric Line Clearance) Regulations 2015*, 23 November 2015.

[40] Letter from Andrew Last (ESV) to Johan Esterhuizen (JEN), *Electricity Safety (Electric Line Clearance) Regulations 2015 – Guidance Information*, 27 November 2015.

[41] Letter from Andrew Last (ESV) to Robert McMillan (JEN), *Electricity Safety (Electric Line Clearance) Regulations 2015*, 30 November 2015.

[42] Memorandum of Advice, *In the matter of the Electricity Safety (Electric Line Clearance) Regulations 2015,* Susan Brennan SC and Marita Foley p 9.

[43] Energy Safe Victoria, *Regulatory Impact Statement, Electricity Safety (Electric Line Clearance) Regulations 2015,* September 2014, p 19.

- JEN could not rely upon the ESV's interpretation to refute an allegation that JEN failed to meet the requirements of the 2015 Regulations.[44] Accordingly JEN could not simply accept the views of ESV or their advice as to how they intended to administer the 2015 Regulations, rather JEN must comply with the terms of the 2015 Regulations as written.

5.3.2 THE EFFICIENT COSTS OF COMPLYING WITH THE NEW OBLIGATIONS

89. Having received the above advice, JEN maintains the view outlined in our April 2015 proposal and the July 2015 submission that JEN should be entitled to a step change for the three drivers of increased cost associated with the changes in the 2015 Regulations, namely:

- **Adoption of amenity tree management standard 4373** – JEN will incur incremental costs as a result of the requirements to engaging inspectors and cutters –with higher qualifications–than are currently required and additional labour costs where mechanical cutters can no longer be used
- **Enhanced notification and consultation provisions** – JEN will incur incremental costs as a result of the new requirements to:
  - Notify owners/occupiers of contiguous land of the details of the intended cutting and removal of any trees, the impact that the cutting or removal of trees may have on their use of the land, one or more days when the intended cutting or removal will commence, contact details for all enquiries regarding the intended cutting and information about JEN's dispute resolution procedures[45]
  - Notify owners/occupiers of private land of the consultation process JEN will follow in relation to any tree to be cut or removed, details of the intended cutting or removal of any trees (including details of whether the tree is of ecological, cultural, environmental, historical or aesthetic significance and a diagram of the tree, where it is in relation to the electric line and where it will be cut), one or more days when the intended cutting or removal will commence, contact details for all enquiries regarding the intended cutting and information on JEN's dispute resolution procedures[46]
  - Notify Councils of details of the intended cutting or removal of the trees (including details of whether the tree is on public land and if it is of ecological, cultural, environmental, historical or aesthetic significance), one or more days when the intended cutting or removal will commence, contact details for all enquiries regarding the intended cutting and information on JEN's dispute resolution procedures[47]
  - Publish notifications of the cutting or removal of any trees in a newspaper circulated in the vicinity of the cutting program which describes the cutting or removal proposed to be undertaken and specifies one or more days when the cutting or removal will commence.[48]
- **[c-i-c]**

90. This submission presents a revised step change setting out the forecast costs JEN expects to incur to comply with the 2015 Regulations. These costs are less than previously proposed in the July 2015 submission. The

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[44] Memorandum of Advice, *In the matter of the Electricity Safety (Electric Line Clearance) Regulations 2015,* Susan Brennan SC and Marita Foley p 16

[45] *Electricity Safety (Electric Line Clearance) Regulations 2015,* sections 15(3)(c), 15(4) and 15(6)

[46] *Electricity Safety (Electric Line Clearance) Regulations 2015,* sections 15(3)(a), 15(4, 15(5)(a) and 15(6)

[47] *Electricity Safety (Electric Line Clearance) Regulations 2015,* sections 15(3)(b), 15(4), 15(5)(b) and 15(6)

[48] *Electricity Safety (Electric Line Clearance) Regulations 2015,* section 16

[49] *Electricity Safety (Electric Line Clearance) Regulations 2015,* sections 20 and 21

revised estimate is a result of consideration of the views of Susan Brennan SC and ESV and the identification of opportunities to incorporate synergies and efficiencies in the field to reduce the compliance costs. JEN's revised cost to comply with the vegetation management obligations is $6.93m ($2015)—a reduction of $8.9m from the costs submitted in our July 2015 submission.

91. Table 5–2 summarises the key drivers and cost to comply with 2015 Regulations and the forecast cost compared to the July 2015 proposal.

Table 5–2: Categories of change in the 2015 Regulations ($2015, millions)

Area of change to 2015 Regulations	July 2015 submission	This submission
Adoption of amenity tree management standard AS 4373	2.25	1.19
Enhanced notification and consultation provisions	12.0	4.61
Assistance provided to councils	1.55	1.13
Total	**15.80**	**6.93**

92. Below, we outline the activities that are key drivers of the cost to comply with 2015 Regulations, how those activities compare with the practice required prior to the commencement of the 2015 Regulations and JEN's approach to estimating the costs of the compliance activities.

5.3.3 ADOPTION OF AMENITY TREE MANAGEMENT STANDARD AS 4373

93. The 2015 Regulations require JEN to adopt amenity tree management standard AS 4373. The mandatory requirement to comply with the whole of AS 4373 will require JEN to adopt different practices in four areas as outlined below:

- The requirement to use Certificate 3 qualified inspectors
- The requirement to use Certificate 2 arborists for cutting
- Removal of the ability to use climbing spikes
- Removal of the ability to use mechanical cutters such as 'jarrafs'.

JEN estimates the cost associated with these changed requirements is $1.19m over the 2016 regulatory period ($1.06m less than the July 2015 submission).

5.3.3.1 Certificate 3 inspectors

94. Prior to the commencement of the 2015 Regulations JEN utilised four inspectors to execute its vegetation management responsibilities. These inspectors were Certificate 2 qualified arborists. Adoption of AS 4373 by the 2015 Regulations means that JEN is now required to utilise Certificate 3 inspectors. JEN's vegetation management contract includes a schedule of prices for each level of qualification. A higher qualification attracts a higher fee. The difference in price between a Certificate 2 and Certificate 3 inspector is [c-i-c] annually. In addition, existing Certificate 2 inspectors will need to be trained to Certificate 3 level standard. The training institutions offering a Certificate 3 Arboriculture qualification[50] charge approximately $2,500 per year for a two-year course to obtain the increased qualification. JEN expects these costs will be passed on to JEN under our contract.

[50] See: Holmesglen , Certificate III in Arboriculture, Program Code AHC30810

95. The additional [c-i-c] per year for four inspectors reflects an increase in costs of [c-i-c] each year. The training costs incurred to qualify JEN's inspectors to a Certificate 3 qualification reflect an incremental cost of $10,000 each year for 2016 and 2017 only. Collectively this is a total cost of [c-i-c] .

96. In its advice to JEN the ESV indicated that the use of the word "should" in AS 4373 means the use of a Certificate 3 arborist is not mandatory.[51] However Susan Brennan SC was of the view that compliance with the standard was mandatory and that it was not open to JEN to seek to defend a failure to use Certificate 3 arborists on the grounds that it would cost more to do so.[52] Thus the ESV's interpretation does not appear to be consistent with the 2015 Regulations or accurately reflect JEN's obligations under those regulations and thus could not be relied upon by JEN or the AER.

5.3.3.2 Certificate 2 arborists for cutting

97. AS 4373 requires JEN to use Certificate 2 arborists for the cutting of trees. JEN considers this obligation reflects the intent of the regulations that the expertise of the arborist is an essential ingredient to ensure the amenity of the tree is protected. JEN has a crew of 12 cutters. Whilst these people have expertise based upon experience, none of these people have Certificate 2 arborist qualifications. To comply with the 2015 Regulations each of these cutters must now achieve a Certificate 2 arborist qualification. Recognising that Certificate 2 Arboriculture qualification can be attained with an element of prior learning (and their experience) we have reduced training cost estimates for the 12 cutters from the amounts sought in our July 2015 submission of $7,500 per cutter to $5,000 per cutter. These estimates are derived from our contractor's experience and reflect current market rates for equivalent training processes. As these are one off training costs, JEN forecast $0.06m per annum to be incurred in 2016 and 2017 only. This results in a total cost of $0.12m for the 2016 regulatory period.

98. The views of the ESV and Susan Brennan SC on this issue are set out in section 5.3.4.1.

5.3.3.3 Non-use of tree climbing spikes/spurs

99. JEN does not propose any additional costs associated with the new requirement to not use climbing spikes. JEN has reviewed its approach prior to the commencement of the 2015 Regulations and identified that occupational health and safety regulations applicable to vegetation management expect that an elevated work platform be used instead of climbing spikes and that where required, an elevated work platform would already be on site. This results in a reduction of $0.175m per annum compared to the July 2015 submission.

5.3.3.4 Non-use of mechanical cutters such as jarrafs or hedgers

100. JEN currently uses mechanical cutters such as "jarrafs" to improve safety and productivity—particularly in less densely populated areas of our network with rows of trees. Jarrafs or hedgers do not provide a clean cut at the collar of a branch. As such the use of a jarraf or hedger is not consistent with the requirements of AS 4373.[53] JEN's vegetation management contractor typically uses mechanical cutters to maintain heavily vegetated spans. Where a hedger/jarraf can no longer be used, additional person-hours are required to cut heavy vegetation using an elevated work platform with a hydraulic chainsaw. A number of areas within JEN's distribution network are affected by the new standard (ie. maintaining Cyprus trees along feeders in Sunbury). JEN estimates that an additional 8 man hours (2 people cutting per span) will be required and charged out at a [c-i-c] , consistent with the contracted rate. JEN forecasts that approximately 250 spans per

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51 Letter, *Electricity Safety (Electric Line Clearance) Regulations 2015 – Guidance Information,* from Andrew Last (ESV) to Johan Esterhuizen (JEN), 27 November 2015, p 2

52 Memorandum of Advice, *In the matter of the Electricity Safety (Electric Line Clearance) Regulations 2015,* Susan Brennan SC and Marita Foley p 6

53 See Australian Standard, *Pruning of Amenity Trees,* AS 4373-2007, Standards Australia, cl 5.1.

year will be affected—based on an average count of the use of mechanical cutters by JEN between 2011 and 2014.

101. JEN considers any cost savings received from not requiring a hedger/jarraf to be on site will be offset by the additional hours of elevated work platform use. Accordingly, the cost estimate provided for this item reflects only the incremental person-hours associated with substituting labour for mechanical cutting tools. This results in a total cost of [c-i-c] ($0.75m over the 2016 regulatory period). This is an increase of $0.1m compared to the July 2015 submission.

102. In considering this obligation the ESV indicated that the avoidance of use of mechanical tools was only required where the amenity of the tree was important to the owner of the tree.[54] However Susan Brennan SC indicated that there was no basis in the 2015 Regulations or AS 4373 for limiting the application of AS 4373 to trees which are identified by owners of having amenity value[55] and that it was not open to distribution companies to elect to comply with the requirements of AS 4373 as they see fit.[56] The ESV's interpretation thereby does not appear to be consistent with the 2015 Regulations or accurately reflect JEN's obligations under those regulations and therefore could not be relied upon by JEN or the AER.

5.3.4 ENHANCED NOTIFICATION AND CONSULTATION PROVISIONS

103. The 2015 Regulations include enhanced notification and consultation obligations. JEN has identified the new obligations above and forecasts the costs associated with these additional requirements are $4.59m over the 2016 regulatory period ($7.41m less than the July 2015 submission). The four new requirements are:

- Notices to owners / occupiers of contiguous land
- Bespoke notices to owners / occupiers of private land
- Notices to Councils
- Publication of notices in a generally circulating newspaper.

5.3.4.1 Notices to owners / occupiers of contiguous land

104. Section 15(3) of the 2015 Regulations contain a new requirement for JEN to notify owner/occupiers of properties that are contiguous to land where a tree is to be cut or removed. In accordance with sections 15(5)(c), 15(4)and 15(6) the notice must provide:

- Details of the intended cutting and removal of any trees
- Details of the impact the cutting or removal will have on that person's use of their land
- One or more days when the intended cutting or removal will commence
- Contact details for all enquiries regarding the intended cutting
- Information on JEN's dispute resolution procedures.

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54 Letter, *Electricity Safety (Electric Line Clearance) Regulations 2015 – Guidance Information,* from Andrew Last (ESV) to Johan Esterhuizen (JEN), 27 November 2015, p 2.

55 Memorandum of Advice, *In the matter of the Electricity Safety (Electric Line Clearance) Regulations 2015,* Susan Brennan SC and Marita Foley p 7.

56 Memorandum of Advice, *In the matter of the Electricity Safety (Electric Line Clearance) Regulations 2015,* Susan Brennan SC and Marita Foley p 8.

105. Prior to the commencement of the 2015 Regulations JEN's practice was to only notify the person whose property is immediately adjacent to a tree on public land. There was also no obligation to provide, or to notify persons about, a dispute resolution procedure.

106. JEN's vegetation management contractor maintains approximately 20,000 vegetated spans per year, of which approximately 80% are on private property (councils are required to maintain public land/nature strips). JEN has identified that these notices must therefore be provided in relation to 20% of our maintained spans.

107. Based on advice of Susan Brennan SC, JEN considers that there is, on average, a three-fold increase in the number of notices JEN will be required to send to meet the obligation to notify owners/occupiers of land contiguous to the land on which a tree is to be cut or removed. This includes notifying people whose use of the land may be impacted by blocking their access by vegetation management machinery or vehicles, the dropping of limbs or the emission of noise or dust. Based on population density in JEN's distribution network, JEN has identified that, on average, it will have to notify four owners or occupiers for each tree to be cut or removed. The contract rate for inspection and issuing notices is [c-i-c] , of which [c-i-c] is directly attributable to the cost of providing notices. JEN believes an average of 20 notices per day was being issued to people in this category. Based on the advice above JEN expects it will now have to issue 80 notices per day of which 60 notices will be additional to current practice. This gives an estimated incremental cost of [c-i-c] ($0.24m over the 2016 regulatory period).

108. In our discussions the ESV indicated that they believed it was only necessary for a DNSP to notify the owner or occupier of the land and no other persons who may be impacted by noise, trucks in the street, dust etc.[57] However Susan Brennan SC indicated that the addition of this requirement to the 2015 Regulations represented a notable change from the previous regulations and that the clear intent of the 2015 Regulations was to ensure owners and occupiers were notified of any works taking place with a focus on identifying impacts on the "use" of the land - thus making this obligation to notify wider than the 2010 regulations.[58] Thus the ESV's interpretation does not appear to be consistent with the 2015 Regulations or accurately reflect JEN's obligations under those regulations and therefore could not be relied upon by JEN or the AER.

5.3.4.2 Bespoke notices for owner / occupiers on private land

109. The 2015 Regulations require notices to be given to an owner/occupier of private land which include:

- Details of the consultation procedure JEN will follow in relation to any tree to be cut or removed
- Details of whether a tree to be cut is a tree of cultural or environmental significance or listed in a planning scheme, or to be of ecological, historical or aesthetic significance
- A diagram that shows the tree, where the electric line is in relation to the tree and where the tree will be cut
- One or more days when the intended cutting or removal will commence
- Contact details for all enquiries regarding the intended cutting
- Information on JEN's dispute resolution procedures.

110. JEN estimates that significant additional work is required to meet these new requirements including:

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[57] Position indicated by ESV at a meeting attended by JEN on 13 November 2015.

[58] Memorandum of Advice, *In the matter of the Electricity Safety (Electric Line Clearance) Regulations 2015,* Susan Brennan SC and Marita Foley p 11 and 12.

- The sending of bespoke notices to owner/occupiers of private land. JEN estimates that approximately 80% of the vegetation JEN is required to manage is located on private property. Due to population density in our distribution network there are often multiple owners or occupiers who JEN would need to contact in relation to each tree which JEN is required to manage
- The necessity to search planning schemes and various other registers to determine whether a tree is of culturally or environmentally significant, listed in a planning scheme, or is of ecological, historical or aesthetic significance in order to include those details in the notice. There was no obligation in the 2010 Regulations to include these details in any notice
- The necessity to make the persons cutting the trees available to deal with any queries in relation to the intended cutting or removal of the trees
- More extensive requirements in relation to the scheduling of works to accommodate the delivery of notices, responding to queries and following any dispute resolution procedures
- The establishment of a dispute resolution procedure, training personnel to follow the process and the administering of that dispute resolution procedure.

111. These new obligations will involve the following additional costs:

- To meet the requirement to provide a diagram of the specific tree with details required by the 2015 Regulations JEN considered a number of different methods of meeting this obligation and determined that the most prudent and efficient method is to take photos of the tree and then apply mark-ups to the images. The identified process involves the inspector taking photos of the trees to be cut at each site and sending them back to the office to be marked up. At the office, bespoke notices will need to be prepared for each customer site matching the image of the tree to the owners or occupiers who need to be notified. The most cost effective approach to comply with these obligations is to engage additional employees to undertake this work.[59] JEN considers an additional 3 office-based employees are required at an annual salary of [c-i-c] , based on current labour market rates being a total of [c-i-c] over the 2016 regulatory period. The number of additional employees has been estimated based on an expectation of 210 working days per year and each employee preparing and distributing no less than 30 notices per day (on average 100 notices per day will be required to be sent to comply with the 2015 Regulations)
- JEN will need to purchase additional equipment and IT software to assist with taking photographic images, marking them up and attaching them to a notice. JEN anticipates additional costs and licencing fees of approximately $0.008 per annum being a total of $0.04m over the 2016 regulatory period
- Due to the need to create a diagram and mark it up, distributing of the bespoke notices will now need to be done via post rather than by handing out generic notices whilst the inspectors are on site. JEN anticipates the incremental cost will be $1.00 per notice (assuming 500 notices per week). This adds an incremental $0.026m per annum ($0.13m over the 2016 regulatory period).
- In order to meet the additional requirements to undertake searches to determine if the trees are of cultural or environmental significance, listed in a planning scheme, or are of ecological, historical or aesthetic significance and to assist with the additional planning and scheduling required to accommodate the delivery of notices, responding to queries and participating in any dispute resolution procedures JEN will need to engage persons with the following skills:
  - Research and planning / scheduling expertise. Based on market data, JEN estimate that such an employee will require an annual salary of [c-i-c] .

59 Employing office-based employees to mark up the images saves substantial labour costs due to paying lower labour unit rates and receiving a faster mark-up process than a Certificate 3 qualified inspector could provide out in the field.

– administrative skills to assist with scheduling, responding to queries from the public about the notices and acting as the first response in any dispute resolution process. Based on similar roles and skill sets JEN anticipates an [c-i-c] .[60]

As the requirement to identify the cultural, environmental, ecological, historical or aesthetic significance of the trees and the additional scheduling tasks apply to both the notices to owners or occupiers of private land and to Councils (see section 5.3.4.3 below), JEN has estimated its staffing requirements to cover both these areas. On that basis JEN anticipates it will need to engage 1.5 persons with research and planning skills at a cost of [c-i-c] over the 2016 regulatory period and 0.5 administrative assistance at a cost of [c-i-c] over the 2016 regulatory period].

- JEN will need to develop a dispute resolution procedure, train employees on the procedure and administer the process. This requirement applies to all categories of notices required by the 2015 Regulations (ie owners and occupiers of contiguous land, owners and occupiers of private land and Councils). JEN anticipates costs of approximately $0.02m per annum to administer the dispute resolution procedure across all these categories. This will add a further $0.1m over the 2016 regulatory period. JEN has included these costs in this section as it is expected that most of the disputes will arise where the tree to be cut is located on private land. As a result, JEN has not separately itemised dispute resolution costs in sections 5.3.4.1 or 5.3.4.3.

112. The total additional cost to JEN attributed to clause 15(5) is $0.70m per annum or $3.5m over the 2016 regulatory period.

113. The ESV indicated that they considered it was acceptable under the 2015 Regulations to provide a representation of the tree and that a photo was not necessary.[61] However as indicated above, JEN considered various options (including the inspectors preparing a representation of the tree) however JEN considered that taking a photo and marking it up was the most cost efficient way to comply with this requirement of the 2015 Regulations. In addition Susan Brennan SC confirmed that the 2015 Regulations did not permit JEN to provide a diagram of a generic tree but rather require JEN to provide an image of the actual tree to be cut, its location to the electric wires and the places in which it will be cut.[62] Thus, to the extent that the ESV consider a generic depiction of the tree to be cut is sufficient, the ESV's interpretation does not appear to be consistent with the 2015 Regulations or accurately reflect JEN's obligations under those regulations and thus could not be relied upon by JEN or the AER.

5.3.4.3 Notices to Councils

114. The 2015 Regulations now require JEN to provide notices to Councils setting out:

- Details of the intended cutting or removal of the trees
- Details of whether the tree is on public land and if it is of ecological, cultural, environmental, historical or aesthetic significance;
- One or more days when the intended cutting or removal will commence
- Contact details for all enquiries regarding the intended cutting

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60 JEN have applied an on-cost ratio of [c-i-c] to administrative roles, consistent with the labour on-costs in Marsden Jacobs Associates, '*Provision of advice in relation to Alternative Control Services, Advice prepared for the AER*', 20 October 2014.

61 Letter, *Electricity Safety (Electric Line Clearance) Regulations 2015 – Guidance Information,* from Andrew Last (ESV) to Johan Estrehuizen (JEN), 27 November 2015, p 2.

62 Memorandum of Advice, *In the matter of the Electricity Safety (Electric Line Clearance) Regulations 2015,* Susan Brennan SC and Marita Foley p. 13 and 14.

- Information on JEN's dispute resolution procedures.

115. Prior to the 2015 Regulations, JEN was not required to provide details to the Councils of whether the tree is on public land and if it is of ecological, cultural, environmental, historical or aesthetic significance, provide contact details for enquiries regarding the intended cutting and was not required to provide a dispute resolution procedure.

116. JEN's vegetation management contractor estimates that 20% of our maintained spans may require these notices to be provided to Councils (i.e. our vegetation management contract anticipates that these trees will be the trees which are located contiguous to private property thus for these trees JEN will be required to provide notices as set out in section 5.3.4.1 of this submission and also a separate notice providing different details to the Council).

117. JEN estimates that it will incur incremental costs in meeting these requirements under the 2015 Regulations including:

- Engaging a staff member with research and planning skills to undertake searches to determine if the trees are of cultural or environmental significance, listed in a planning scheme, or are of ecological, historical or aesthetic significance and to assist with the additional planning and scheduling required to accommodate the delivery of notices, responding to queries and participating in any dispute resolution procedures
- Engaging a person with administrative skills to assist with scheduling, responding to queries from the public about the notices and acting as the first response in any dispute resolution process
- Providing a dispute resolution procedure.

118. JEN has included the incremental costs of complying with these obligations in section 5.3.4.2 of this attachment

119. The ESV has not commented on these additional obligations.

120. JEN considers that it will incur the incremental costs set out in this step change as a result of changes to the 2015 Regulations.

5.3.4.4 Publish notice in a generally circulating newspaper

121. The new requirement to publish notices "in a newspaper circulating generally in the locality of the land in which the tree is to be cut or removed" for trees that JEN has electric line clearance responsibility, requires JEN to incur incremental costs, as practice prior to the commencement of the 2015 Regulations does not include the obligation to publish notices in newspapers. As the cutting is on a continuous program, the frequency of the notice advertisements is dependent upon how quickly the vegetation management program moves through suburbs and different council (and newspaper distribution) zones. JEN has revised its estimated cost of advertisements by assuming a greater reach (4 suburbs) for each municipal newspaper.

122. JEN's forecast of the additional costs is based on publishing four notices per month (ie. 48 notices per year) to advise the public of the intended areas and dates, at a unit rate of $2,200 per advertisement (based on quotes obtained from council newspapers in JEN's network region). This equates to an incremental cost of $0.11m per annum. JEN expect to incur additional labour costs associated with administering the newspaper advertisement requirements. JEN has estimated the required incremental work effort at half an additional employee to administer the advertisement requirements. JEN estimate that an annual salary of [c-i-c] (based on current market rates for an office administrator with relevant experience) will add a further $0.06m per annum to the total cost of publishing notices in generally circulating newspaper.

123. The total incremental cost to publish notices of the intended cutting in a generally circulating newspaper is $0.17m per annum ($0.85m in total over the 2016 regulatory period).

124. The ESV indicated that the intention of the notification arrangements is to make residents and the community aware of the impending works and that the ESV expects this intent to be achieved.[63] JEN considers that its proposal meets the ESV's intent.

5.3.5 [C-I-C]

5.3.6 SUMMARY OF COSTS OF COMPLYING WITH 2015 REGULATIONS

132. Table 5–3 sets out the incremental costs of each activity described above for each year and the change since the July 2015 submission.

[66] Letter, *Electricity Safety (Electric Line Clearance) Regulations 2015 – Guidance Information,* from Andrew Last (ESV) to Johan Esterhuizen (JEN), 27 November 2015, p 3.

[67] Memorandum of Advice, *In the matter of the Electricity Safety (Electric Line Clearance) Regulations 2015,* Susan Brennan SC and Marita Foley p 15.

Table 5–3: Summary of costs to comply with 2015 Regulations

Regulations compliance categories	Sub categories	Step change forecast						Comparison to April 2015 proposal
		2016	2017	2018	2019	2020	Total	
Amenity tree management standard AS 4373	Use no less than a Certificate 3 qualified arborist for inspection	0.07	0.07	0.06	0.06	0.06	0.32	0.02
	Use no less than a Certificate 2 qualified arborist for cutting	0.06	0.06	0	0	0	0.12	-0.33
	Non-use of tree climbing spurs/spikes	0	0	0	0	0	0	-0.88
	Use of mechanical cutters such as jarrafs	0.15	0.15	0.15	0.15	0.15	0.75	0.12
	Sub total	**0.28**	**0.28**	**0.21**	**0.21**	**0.21**	**1.19**	**-1.06**
Enhanced Notification and Consultation provisions, (Schedule 1 Part 2 Division 3 Clause 15)	**Notices to owners of contiguous land** *Trees not on private property (Notices to customers of 20% of spans maintained)* (3)(c) A notice must be given to owners of contiguous land to which a tree is to be cut or removed. The notice must contain details and a diagram in accordance with clause 15(5).	0.05	0.05	0.05	0.05	0.05	0.24	-6.36
	Bespoke notices for owners/occupiers of private land *Applies to trees on private property (80% of spans maintained)* The written notice must include additional information:	0.70	0.70	0.70	0.70	0.70	3.50	-0.35
	(5)(c) …details of the impact that the intended cutting or removal may have on the affected person's use of their land during the cutting or removal and (5)(a)(iii) … a diagram that shows the tree and where the electric line is in relation to the tree and where the tree will be cut.							

Regulations compliance categories	Sub categories	Step change forecast						Comparison to April 2015 proposal
		2016	2017	2018	2019	2020	Total	
	Notices to Councils	Included in costs for notices to owners of private property	Included in costs for notices to owners of private property	Included in costs for notices to owners of private property	Included in costs for notices to owners of private property	Included in costs for notices to owners of private property	Included in costs for notices to owners of private property	N/A
	Publish notification in newspaper *Applies to 20% of spans maintained* Clause 16(3) A written notice published under subclause (2) must be published in a newspaper circulating generally in the locality of the land in which the tree is to be cut or removed.	0.17	0.17	0.17	0.17	0.17	0.85	-0.50
	Sub total	**0.92**	**0.92**	**0.92**	**0.92**	**0.92**	**4.59**	**-7.39**
[c-i-c]	[c-i-c]	0.26	0.22	0.22	0.22	0.22	1.15	-0.41
	[c-i-c]							
	[c-i-c]							
	[c-i-c]							
	Sub total	**0.26**	**0.22**	**0.22**	**0.22**	**0.22**	**1.15**	**-0.41**
	Grand total step change	**1.60**	**1.42**	**1.35**	**1.35**	**1.35**	**6.93**	**-8.83**

5.3.7 OFFSETTING COSTS ASSOCIATED WITH THE RELAXATION OF REGULATIONS IN RELATION TO MAINTAINING STRUCTURAL BRANCHES

133. The preliminary decision suggested that JEN might reduce its vegetation management costs as a result of the re-introduction in the 2015 Regulations of exceptions in relation to the maintenance of structural branches around insulated and non-insulated conductors. The AER sought the views of the ESV on this matter: [68]

> "…*We are most interested in the ESV's views on the reinstatement of the 2005 code for the exception to the minimum clearance space for insulated cables and the enhanced notification requirements.*
>
> *Five years ago the AER provided a step change for the removal of the insulated cable exception. Now that the exception has been reinstated does this mean you would expect a corresponding decrease in costs?"*

134. In the preliminary decision the AER indicated that the ESV:

> "…*expects the reintroduction of these exceptions in ELC 2015 should decrease pruning costs over time"*[69]

and that the AER:

> "…*would expect a similar decrease in costs to the increase allowed in the 2011 – 2015 period."* (stated by the AER to be $3.4 million).[70]

135. In considering the preliminary decision JEN sought advice from:

- The ESV
- IJM Consulting Pty Ltd (**IJM**) being the entity which conducted the Annual Vegetation Management Audit of JEN's distribution area on behalf of the ESV for the years 2011 to 2014 and
- An arborist employed by JEN's vegetation management contractor, Select Solutions Group Pty Ltd (**Select**)

as to the impact upon JEN of the re-introduction of the exceptions with respect to structural branches in the 2015 Regulations.

5.3.7.1 The ESV does not expect the change in regulations to translate into cost savings for JEN

136. On 13 November 2015 JEN met with the ESV to discuss, inter alia, the benefits to DNSPs arising from the re-introduction of the exceptions in relation to structural branches in the 2015 Regulations.

137. By letter dated 23 November 2015 JEN wrote to the ESV seeking formal guidance on this issue. [71]

138. By letter dated 30 November 2015 the ESV responded to JEN query by advising that:

> "…*In relation to the reintroduction of these exceptions*, *ESV does not see a significant reduction in effort from existing practices by the distribution businesses when carrying out electric line clearance activities in*

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[68] Document titled 'ESV audit intent', drafted by ESV and relied upon by the AER in the preliminary decision.

[69] AER, *Jemena Preliminary decision 2016-20, Attachment 7 – Operating expenditure*, 29 October, 2015, p 7-72.

[70] AER, *Jemena Preliminary decision 2016-20, Attachment 7 – Operating expenditure*, 29 October, 2015, p 7-72 and p 7-73.

[71] Letter titled *Guidance on compliance and audit under Electricity Safety (Electric Line Clearance) Regulations 2015,* from Robert McMillan (JEN) to Paul Fearon (ESV), 23 November 2015.

accordance with the Electricity Safety (Electric Line Clearance) Regulations 2015 and its Code…".[72] (see Attachment 8-8).

139. This supports JEN's view that the changes in the 2015 Regulations relating to structural branches do not translate to cost savings for JEN.

5.3.7.2 Advice of arboreal experts

140. To further test this position JEN sought advice:

- From IJM as to;
  - Details of any non-compliances by JEN with the 2010 regulations relating to structural branches identified in the annual ESV audits for the years 2011 to 2014; and
  - The results of a spot audit of 100 sites (chosen by IJM) in JEN's distribution area testing JEN's compliance with the 2010 regulations in relation to structural branches.
- From Select as to the likelihood of a structural branch growing into the clearance zone specified in the 2010 regulations (and hence the zone established by the exceptions in the 2015 Regulations).

141. In seeking this advice JEN was trying to establish whether there were any structural branches that were within, or likely over the cutting cycle to come within, the zone in which the exceptions re-introduced into the 2015 Regulations were to apply, thus potentially providing JEN with a benefit of delaying cutting which would otherwise have been required under the 2010 Regulations.

5.3.7.3 Advice of IJM – No structural branches in the 2010 Regulation clearance space

142. JEN engaged IJM, the auditor the ESV had engaged in the 2011 regulatory period to audit JEN for compliance with the 2010 regulations, to conduct a desk-top audit of JEN's compliance with the 2010 regulations specifically relating to compliance with maintenance of structural limbs.

143. IJM indicated that the results of the 2011 to 2014 annual audits showed that JEN:

> "…*had progressively moved to achieve total compliance with the Code of Practice within the Electricity Safety (Electric Line Clearance) Regulations 2010 for removal of all vegetation within the clearance space over the past 5 years…*"[73]

144. JEN also requested IJM to undertake a spot audit (at sites to be determined by IJM) of JEN's compliance in 2015 with the regulations in relation to structural branches. IJM found that :

> "…*special notice was taken by the auditor to determine if structural limbs, as described in the Electricity Safety (Electric Line Clearance) Regulations 2015 schedule 1 – Code of Practice for Electric Lines, contravened this requirement. No sites were found…*"[74]

IJM also noted:

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72 Letter titled Electricity Safety (Electric Line Clearance) Regulations 2015, from Andrew Last (ESV) to Robert McMillan (JEN), 30 November 2015

73 Report, Review of JEN's 2011 -2014 Annual Vegetation Management Audit and 2015 Spot Audit, IJM Consulting Pty Ltd, 1 December 2015, p 15 (see Attachment 8-4).

74 Report, Jemena Electricity Vegetation – Line Clearance audit 2015, IJM Consulting Pty Ltd, 1 December 2015, p 1, footnote 13 (see Attachment 8-4).

"…*This is an outstanding result that in the auditor's opinion demonstrates that JEN was complying with the intent of the Electricity Safety (Electric Line Clearance) Regulations 2010…*"[75]

145. JEN considers that this result shows that, given no structural branches were found to be in the zone which would require JEN to cut structural branches under the 2010 Regulations, it is apparent there are no limbs currently within zone in which the exceptions—re-introduced in the 2015 Regulations—would apply.

5.3.7.4 Advice of Select – No structural limbs will grow into the clearance space specified in the 2010 regulations within JEN's cutting cycle

146. To further test this position, JEN also sought advice from an arborist as to the likelihood that any structural branches would grow into the clearance space designated by the 2010 regulations during JEN's cutting cycle in the 2016 regulatory period.

147. JEN obtained an advice from Shane O'Keeffe, an arborist employed by Select. Select are JEN's vegetation management contractor and are familiar with the types of trees, and patterns of growth of those trees, within JEN's distribution network.

148. Mr O'Keeffe indicated:

"…*that the likelihood of a new structural branch entering the clearance space (as defined by the 2010 Electricity Safety (Electric Line Clearance) Regulations) within a two year clearance cycle is unlikely. This supposition is founded from several years of monitoring different types of vegetation growing at different site locations within the JEN area. In that time, we cannot recall any instances of this type of growth…*"[76]

and

"…*the likelihood of any branch growing to 130mm or greater at the point it enters the clearance space within a two year pruning cycle is highly unlikely*…"[77]

149. Based upon this advice, JEN considers that as it is unlikely that any structural branches will grow into the clearance spaces designated by the 2010 regulations within the cutting cycle and thus there will be no instances of structural branches growing into the zone in which the exceptions re-introduced in the 2015 Regulations would apply.

5.3.7.5 Conclusion – No benefit to JEN of re-introduction of structural branches exceptions

150. Based on the views of the ESV, IJM and Select, JEN does not consider that the re-introduction of exceptions for the maintenance of structural branches will result in any cost savings for JEN and therefore should not be considered an offset for the cost increases arising from the introduction of the other new obligations under the 2015 Regulations.

5.3.8 ELECTRICITY SAFETY AMENDMENT (BUSHFIRE MITIGATION) ACT 2014 – REMOVAL OF ROADS CORPORATION AS A RESPONSIBLE PERSON

151. JEN maintains in this submission the position in its April 2015 proposal and July 2015 submission that it will incur additional costs associated with the removal of Roads Corporation as a responsible person from the Electricity Safety Amendment (Bushfire Mitigation) Act 2014.

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[75] Ibid, p1 General Comment Covering HBRA & LBRA (Jemena Electricity Responsibility to clear).

[76] Letter, *Re: Jemena Electricity Network (Vic) Ltd vegetation growth rates,* from Shane O'Keeffe (Select) to Johan Esterhuizen (JEN), 8 December 2015. (see Attachment 8-5).

[77] Ibid, p 1.

152. JEN has completed an assessment of the areas affected by the regulatory change and has determined that JEN is responsible for approximately 565 additional spans as a result of this change.

153. As of 1 April 2014, JEN has been responsible for maintaining electric line clearance for these areas and vegetation management activities have already commenced. However, expenditure in the balance of 2014 (i.e. April 2014 to December 2014) does not represent a full representative year of expenditure.

154. Ongoing vegetation maintenance requires an incremental $0.09M in 2016 only to bring us to a compliant state relative to 2014 expenditure.

155. The AER did not respond to this proposal in the preliminary decision.

156. JEN considers that:

- These are costs it will incur as a result of changes to the regulatory obligations which apply to JEN in the 2016 regulatory period

157. That it is entitled to a step change for these costs as this is consistent with the operating expenditure criteria, necessary to promote the operating expenditure objectives, necessary to ensure that JEN is provided the opportunity to recover at least its efficient costs to comply with the new vegetation management obligations, consistent with the AER's assessment approach and necessary to attain the Optimal NEO position.

5.4 CONCLUSION

158. JEN maintains that:

- We will incur additional costs associated with the 2015 Regulations and changes to the Electricity Safety Amendment (Bushfire Mitigation) Act 2014 and that such costs are not compensated via base opex or accounted for by applying an annual rate of change escalation
- JEN's step change proposal satisfies the AER's assessment approach
- The amount included in the step change are costs which a prudent and efficient service provider would need to meet the new obligations imposed by the vegetation management obligations, are estimated based on JEN's consideration of the incremental activities compared to those occurring prior to the commencement of the vegetation management obligations and reflect JEN's efficient, market-tested contracting arrangements
- JEN will not obtain any offsetting cost benefit from the re-introduction of exceptions in relation to structural branches and thus the net impact to JEN of the new vegetation management obligation is the amount set out in this step change proposal
- The step change is necessary in order to satisfy the operating expenditure criteria, to promote the operating expenditure objectives, to ensure that JEN is provided with the opportunity to recover at least its efficient costs to comply with the new vegetation management obligations and to attain the Optimal NEO position.

159. Table 5–4 below presents the efficient costs JEN will incur to comply with the new vegetation management obligations.

Table 5–4: Vegetation management step change forecast ($2015, millions)

Step change	2016	2017	2018	2019	2020	Total
Vegetation management	1.45	1.42	1.35	1.35	1.35	6.93

6. ENERGY SAFE VICTORIA CODE OF PRACTICE CHANGES

6.1 JEN'S APRIL 2015 PROPOSAL

160. JEN proposed a step change in opex to reflect the forecast costs of responding to the process to review the Code of Practice for Electrical Safety (**Blue Book**), which is expected to occur during the 2016 regulatory period. The opex step change forecast is $0.93m over the period.

161. JEN outlined in section 8 of Attachment 8-6 of the April 2015 proposal the supporting information for this step change, including forecast cost and the basis for the forecast costs.

6.2 PRELIMINARY DECISION

162. The preliminary decision did not include an opex step change for this program. The AER does not consider that updating the Code of Practice for Electricity Safety is a new regulatory obligation and responding to this process is a business as usual expense that is accounted for in base year opex. Further, the cost that might be associated with the review is uncertain.

6.3 JEN'S RESPONSE AND THIS SUBMISSION

163. We note the AER's position is to not approve this step change because it is not a new obligation, is considered business as usual and is covered in base year opex. We have incorporated the AER's position into our submission on the basis that the costs are uncertain and, although JEN has made best endeavours to estimate the activities that would be required and the associated costs, the timing of the costs are also uncertain.

164. As a result, JEN has not included a step change in this submission for responding to the process to review the Blue Book.

7. VULNERABLE CUSTOMER ASSISTANCE

7.1 JEN'S APRIL 2015 PROPOSAL

165. JEN recognises that a number of our customers are struggling to pay rising electricity bills. Through engagement with, and research, into JEN's customer base, JEN has found that a number of its customers are likely to be particularly vulnerable to rising energy prices.

166. JEN engaged extensively with its customers and stakeholders about ways it could assist vulnerable customers, and proposed targeted vulnerable customer support initiatives as an opex step change, that reflected the feedback received as part of that engagement process. The customer initiatives proposed include:

- A trial of in home display device for 500 customers to monitor energy usage
- No interest loan scheme funding to purchase new, more energy efficient appliances
- Improved communications for culturally and linguistically diverse customers and focus group tested energy literacy material
- Additional community partnerships to develop material to help customers better understand energy efficiency and costs.

7.2 PRELIMINARY DECISION

167. The preliminary decision did not allow vulnerable customer assistance as a step change. The AER noted that the Victorian Department of Economic Development, Jobs, Transport and Resources (**DEDJTR**) stated that the ESC is currently undertaking an inquiry into best practice financial hardship programs of energy retailers, and that DEDJTR indicated that the AER should await the outcomes of that report (expected in late 2015) before accepting any step change. The AER accepted the submission of DEDJTR: [78]

> *The DEDJTR submitted that if the inquiry reveals there is a role for the distribution network service providers in providing assistance to vulnerable customers, the AER should consider the level of expenditure required at that time, rather than seek to pre-empt the outcomes of the inquiry.*
>
> *On the advice of the DEDJTR, we have not included these costs in our forecast.*

7.3 JEN'S RESPONSE AND THIS SUBMISSION

168. We do not agree with the preliminary decision on the step change for vulnerable customer assistance.

169. The ESC's hardship review[79] is retailer focused and in no way duplicates, nor effects, the initiatives JEN is proposing.

170. The AER has not considered the direct feedback and support we received from customers on our April 2015 proposal, nor is it clear whether the AER has received any information from customers that would suggest that

78 AER, *Jemena Preliminary decision 2016-20, Attachment 7 – Operating expenditure*, 29 October, 2015, p 7-74.

79 ESC, *Supporting customers, avoiding labels, energy hardship inquiry draft report*, September 2015.

the proposed program would not be in customers' long-term interests. For example, CUAC's public submission states:[80]

> *…CUAC is strongly supportive of Jemena's proposed assistance to vulnerable customers: in home displays; funding to No Interest Loan Schemes; improved communication with culturally and linguistically diverse (CALD) consumers. Jemena involved the ECC both in the choice of programs and aspects of their implementation, e.g. partnering with existing providers rather than establishing new programs. Distribution businesses have responsibilities toward their consumers, some of whom are low income, vulnerable, or CALD groups.*

171. On 18 November 2015 we engaged further with the JEN Customer Council on the AER's preliminary decision, including the AER's decision on vulnerable customer initiative. The Customer Council:

- Reiterated there was a real opportunity for distribution businesses to play a unique and targeted role in assisting vulnerable customers
- Expressed the view that assistance provided by distribution businesses needs to fit within a broader hardship assistance package, and should not overlap with or blur responsibilities for assistance provided by other organisations
- Expressed significant support for JEN's proposed vulnerable customer support package.[81]

172. JEN's proposed initiatives are targeted in nature, and reflect our comparative advantages as a distributor in providing meaningful and effective support for vulnerable electricity customers in JEN's network area. Our initiatives are not broad-based hardship programs. They involve using our expertise as an energy asset owner and manager, and leverage our pre-existing relationships with community groups.

173. It is not appropriate for the AER to:

- Disregard the evidence provided by JEN that our customers value and support the initiatives proposed and the submission from CUAC
- Given this value—not provide for the efficient costs of delivering these initiatives in forecast opex.

174. JEN is uniquely placed to play a role in supporting vulnerable customers which is in the long term interests of all customers. Therefore, enabling JEN to recover the efficient costs of this initiative promotes the Optimal NEO Position.

175. JEN's submission for the step change for vulnerable customer assistance is the same as its April 2015 proposal and is presented in Table 7–1.

Table 7–1: Vulnerable customer assistance step change forecast ($2015, millions)

Step change	2016	2017	2018	2019	2020	Total
Vulnerable customer assistance	0.22	0.20	0.20	0.20	0.20	1.01

80 CUAC, *Re: Victorian electricity distribution pricing review (EDPR), 2016 to 2020*, 13 July 2015.

81 See section 2.1 of Attachment 1-3 to this submission.

8. CUSTOMER ENGAGEMENT

8.1 JEN'S APRIL 2015 PROPOSAL

176. JEN proposed a step change in opex to deliver customer engagement initiatives over the next regulatory period. The total step change in opex is $0.93m. The amount varies each year to reflect the expected activities in each year.

177. JEN outlined in section 10 of Attachment 8-6 of the April 2015 proposal the supporting information for this step change, including forecast cost and the basis for the forecast costs.

8.2 PRELIMINARY DECISION

178. The preliminary decision did not include a category specific forecast for this program. Instead, the AER retained these costs from the base year opex.

8.3 JEN'S RESPONSE AND THIS SUBMISSION

179. We note that the AER's position is to include the costs associated with the regulatory determination process (which included costs associated with customer engagement) in the base year opex forecast to avoid incorporating category-specific forecasting approaches.

180. JEN has incorporated the approach taken in the preliminary decision into our submission on the basis that it does not significantly change the outcome given:

- the efficient costs forecast by JEN
- the timing of efficient forecast costs
- that at this time, JEN does not forecast penalty under the EBSS for the next period.

181. JEN's views regarding this approach are the same as those relating to the regulatory proposal opex step change as outlined in section 4.3.

9. POLE-TOP FIRE EARLY DETECTION PROGRAM

9.1 JEN'S APRIL 2015 PROPOSAL

182. JEN proposed a step change in opex to undertake an early fault detection (**EFD**) system to detect low levels of partial discharges on pole top structures. This technology is expected to reduce the risk of pole fire incidents as well as pole top fire mitigation expenditure to maintain fire safety levels on the network.

183. The program will run during the 2016 regulatory period and include leasing multiple pole-top EFD systems and testing the system on a number of feeders. The program will provide the information necessary to design a program that can defer expenditure that otherwise might be required in the next regulatory period.

184. The step change in opex is for $0.28m per year ($1.38m over the 2016 regulatory period).

185. JEN outlined in section 11 of Attachment 8-6 of its April 2015 proposal the supporting information for this step change, including forecast cost and the basis for the forecast costs.

9.2 PRELIMINARY DECISION

186. The preliminary decision determined that JEN does not require an increase in opex for this program. The preliminary decision indicated that no increase in opex is required because this activity is not in response to a new obligation but rather should result from a reallocation of opex budget to meet changing priorities. Further, the preliminary decision suggested that undertaking this program may result in benefits to JEN; from reducing capex and receiving benefits through the CESS, and improving service performance that may result in benefits through the STPIS. The AER expects JEN to weigh up the costs and benefits of the initiative and decide whether it is worth funding as there is no compelling reason why JEN should receive additional funding form its customers to pursue efficiencies.

9.3 JEN'S RESPONSE AND THIS SUBMISSION

187. We do not agree with the preliminary decision with regard to the pole top fire detection trial for the following reasons:

- The benefit from undertaking the program is to gain further information to make better decisions about the program and implementation in the future
- Benefits are expected from the program, however, any benefits in the form of cost savings, capital deferral, service improvements or financial payments under incentive schemes will not accrue until subsequent regulatory periods
- The preliminary decision shows a bias against initiatives that facilitate dynamic efficiency and thus cannot best support the Optimal NEO position.

188. There is no incentive for JEN to undertake the trial if it is unable to recover its efficient costs of doing so. There will not be any capex deferral benefits in the current regulatory period. JEN will be required to deliver its full planned capex program in parallel with the EFD program during the 2016 regulatory period. JEN will not realise CESS benefits directly. If successful, the technology could defer capex in the 2021 regulatory period.

189. The EFD program could identify significant cost savings in maintaining network fire safety and deliver benefits to customers in the form of reduced fires – which could reduce safety risk and reliability. In recent times, network fire incidents have received increased scrutiny by the safety regulator, ESV and the media. It is in the best interests of customers to investigate all potential options for pole fire mitigation.

190. JEN has compared the costs and benefits of an EFD system with its current approach to fire risk management and other options. The assessment compares programs once implemented. This analysis is based on the application of the EFD program to only 2 feeders out of 12 and the value of improved safety outcomes or improved information to be utilised in future decisions about the program are not quantified in the analysis.

191. The assessment indicates that there is potential for the EFD program to result in:

- deferred capex of around $0.5m per year in future regulatory periods based on an assessment of 2 feeders
- savings in opex associated with responding to pole top fire faults and a reduced cost of damaged assets through early detection and proactive replacement
- additional benefits such as maintaining service and risk performance.

192. The comparison of approaches considers the following options (reflecting those considered as part of the Pole Top Fire Mitigation Strategic Planning Paper[82]):

1. Accelerated replacement of pole top structures – replacing all existing HV and ST wooden crossarms that have brown fog, brown post and brown disc insulators at a rate of 1,400 crossarms (increased from the current rate of 475 crossarms) per annum
2. Targeted replacement of pole top structures (current approach) – inspection programs take place to prioritise deteriorated pole tops and replace 650 crossarms per annum. This is the option included in the proposed repex for the 2016 regulatory period
3. Treat insulators – this option involves the washing or coating of insulators to reduce the effect of dust accumulation
4. Early fault detection implementation (2 feeders per year) – assumes that two feeders out of twelve can be 100% successfully risk managed using the EFD technology, allowing capex on those feeders to be deferred by one year (approximately 16.7% of the capex program). The remainder of the capex program will continue as per option 2.

193. The key assumptions underpinning the cost benefit assessment are as follows:

- The direct cost unit rate is $3,864[83] per crossarm replacement. The scope of work per crossarm includes surveys, inspection, changing of the crossarm and insulators but does not include costs of any opportunistic maintenance i.e. pole replacement
- An average of 40 pole top fires per year have been assumed based on JEN's experience with the last 6 years of pole fire events
- 14,000 high-risk crossarms (i.e. wooden HV & ST crossarms) remain on the electricity network consistent with JEN's Strategic Planning Paper[84]

[82] JEN, *ELE PL 0015 Pole Top Fire Mitigation*, p 11.

[83] JEN, *ELE PL 0015 Pole Top Fire Mitigation*, p 17.

[84] JEN, *ELE PL 0015 Pole Top Fire Mitigation*, p 15.

- Although this program is safety driven, there are no quantified safety benefits included in the cost benefit assessment
- The assessment has been undertaken over a 25 year assessment period.

194. Table 9–1 presents the results from the cost benefit assessment and residual risk assessment associated with each option.

195. The residual risk assessment presented in Table 9–1 has been undertaken consistent with JEN's corporate risk framework. The 'do nothing' risk assessment of a pole top fire event was assessed as having "Major" consequences and "Possible" likelihood. Pole top fires impact upon reliability of supply to customers as well as pose safety threats where fires can cause property damage or injury. The JEN network experiences pole top fire events every year under conducive conditions and where wooden pole top hardware is in place. Since the current pole top fire mitigation investment was assessed to reduce the likelihood to "Rare" the overall (residual) risk rating is reduced to "Moderate". Implementation of a 100% successful EFD system is assumed to result in the same residual risk.

196. The benefits of the program captured in the analysis include a reduction in operating and maintenance expenditure in responding to pole top fire faults (including high cost after hours events), a reduced cost of damaged assets and a reduction of energy at risk, which uses a value of customer reliability (**VCR**) of $38,400/MWh.[85]

Table 9–1: Cost benefit assessment for pole top fire options if implemented in 2021 ($2015, millions)

Option No.	Option	Opex per year	Capex per year	NPV - 25 years	Residual Risk
1	Accelerated replacement	0	5.53	49.7	Significant
2	Targeted replacement (current approach)	0	3.34	23.9	Moderate
3	Insulator washing	4.07	0	-14.9	High
4	Insulator coating	2.79	0	-24.0	High
5	Pole top early detection system implementation	0.28	2.78	33.4	Moderate

197. JEN will not receive a financial benefit from operating or capital efficiencies arising in the 2016 regulatory period under the EBSS, capital expenditure sharing scheme (**CESS**) or service target performance incentive scheme (**STPIS**). Indeed, JEN would be penalised under the EBSS if JEN proceeded with program in the absence of an approved step change.

198. The above analysis indicates that if the program is not undertaken, JEN's customers may be worse off by $9.0m over the longer term. This does not take in to account the benefits from reduced fire risk on safety outcomes for the community but does illustrate the foregone dynamic efficiency gain if the AER retails its positon in the preliminary decision.

199. Therefore, JEN maintains that providing an opex step change to ensure the recovery of the efficient costs of undertaking this program to inform future decisions on efficient investment promotes the Optimal NEO Position. This is because it is desirable for JEN to pursue and test initiatives that reduce the costs of delivering services over time and deliver benefits to customers. If successful, JEN's customers can receive the benefits associated with lower expenditure (to maintain network safety levels) and reduced fire risk over the longer term.

[85] AEMO, *Value of Customer Reliability Review Final Report*, September 2014.

200. JEN's submission for the step change for the pole top fire early detection program is unchanged from the April 2015 proposal presented in Table 9–2.

Table 9–2: Pole top early detection system step change forecast ($2015, millions)

Step change	2016	2017	2018	2019	2020	Total
Pole top early detection system program	0.28	0.28	0.28	0.28	0.28	1.38

10. MANAGEMENT CAPEX/OPEX TRADE-OFF

10.1 JEN'S APRIL 2015 PROPOSAL

201. JEN proposed a step change in opex for the forecast cost of undertaking two specific demand response (**DR**) programs to mitigate two network constraints and limit potential risk of supply interruption to customers that would otherwise need to be address through a capex response. The areas are:

- Footscray East (**FE**) and
- North Heidelberg (**NH**) and Watsonia (**WT**)

202. By deploying these programs, network augmentation works can be prudently deferred to the next regulatory period. The step change in opex is for $0.71m over the 2016 regulatory period.

203. JEN outlined the supporting information for this step change in section 12 of Attachment 8-6 of the April 2015 proposal. This included forecast costs and the basis for the forecast costs.

10.2 PRELIMINARY DECISION

204. The preliminary decision was satisfied that the additional opex associated with JEN's demand management program is an efficient capex/opex trade-off.

10.3 JEN'S RESPONSE AND THIS SUBMISSION

205. We welcome the AER's acceptance of our April 2015 proposal on demand response programs. We understand that the AER's decision is based upon the size of the deferred capex savings outweighing the respective costs for each of the demand response programs and therefore it is efficient to increase opex to finance both of these projects. We agree with the AER because providing for an opex step change that results in deferred capex—giving rise to a higher NPV.

206. We confirm our submission promotes the Optimal NEO Position because it supports distribution network service providers to identify demand response solutions and efficiently defer capex over time without penalising the distribution network service provider because of the strong incentive to achieve lower operating costs.

207. JEN's submission for the step change is the same as its April 2015 proposal for the demand response program and is presented in the Table 10–1.

Table 10–1: Demand response program step change forecast ($2015, millions)

Step change	2016	2017	2018	2019	2020	Total
Demand response program	0.11	0.15	0.15	0.15	0.15	0.71

11. [C-I-C]

11.1

[C-I-C] [redacted] — 11

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

12. NEW TARIFF IMPLEMENTATION

12.1 JEN'S APRIL 2015 PROPOSAL

218. JEN proposed a step change in opex to enable it to comply with new obligations relating to pricing arrangements contained in the NER. The step change relates to forecast opex for the transition to kVA demand charges and the introduction of capacity based prices for residential and small business customers in line with the new network tariff requirement. This includes required changes to billing systems.

219. JEN plans to transition to the kVA based demand charges from 1 January 2017; these are published in our Tariff Structure Statement[90] (**TSS**) and will commence on 1 January 2017. JEN will not start billing for the demand of residential and small business customers until 1 January 2018 to allow time for retailers to prepare their systems and will pursue an 'opt in' approach consistent with the Victorian Government's policy direction.[91] The migration, customer education and tariff promotion process will need to start in June 2016, six months prior to the introduction of new tariff structures, to ensure the transition commencement date is met.

220. Customers expressed direct support for this transition path.[92] The step change in opex is for $2.46m over the 2016 regulatory period.

221. JEN outlined in section 14 of Attachment 8-6 of the April 2015 proposal the supporting information for this step change, including forecast cost and the basis for the forecast costs.

12.2 PRELIMINARY DECISION

222. The preliminary decision included a step change in opex for costs relating to the Australian Energy Market Commission (**AEMC**) network pricing arrangement rule change.[93] The AER considered that the new pricing framework results in a new set of obligations for JEN relative to the current pricing rules. The AER considered the forecast reasonable based on its assessment of the detailed costing of the step change.

12.3 JEN'S RESPONSE AND THIS SUBMISSION

223. We welcome the preliminary decision's acceptance of our April 2015 proposal for the step change for implementing new tariffs. We understand that the AER's decision is based on an assessment that the detailed information on the activities, timing and costs associated with the transition. We agree with the preliminary decision that costs associated with the transition must be included as a step change under the expenditure assessment framework[94] and allow JEN to recover the efficient costs of providing services.

224. We have updated the cost build up for our step change to account for the Victorian Government's policy direction notified to us on 21 December 2015. The direction requires us to provide demand tariffs only on an 'opt

90 JEN, *Tariff Structure Statement*, September 2015.

91 See letter from the Minister of Energy and Resources to Paul Adams, *Distribution network pricing arrangements,* 21 December 2015.

92 See attachment 4-1 in our April 2015 proposal on customer, stakeholder and community engagement.

93 AEMC, *Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014.

94 AER, *Better Regulation, Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013.

in' basis for residential and small business customers not currently subject to a demand tariff. While much of step change justification is as detailed in our April 2015 proposal, the key changes are:

- Reduced volumes of service calls and billing disputes 2016 and 2017 (to primarily facilitate the changes to large business tariffs), but increased volumes for 2018-20 (to facilitate residential and small business queries on opt in tariffs when the tariff is promoted)[95]
- Reduced IT support to facilitate a single transfer of residential and small business customers onto the new demand tariffs, and additional ongoing support to facilitate ongoing transition between tariffs following promotional activities
- Higher levels of promotional activity (aimed at retailers and customers) to achieve take up of cost reflective tariffs[96]
- Accommodating the increase in mail postal rates.[97]

225. Note that certain costs will not change from our April 2015 proposal given:

- JEN will still need to undertake mail outs to supplement promotional activity to enable take-up of the cost reflective tariffs and to assist achieving the pricing principle in the NER that customers understand the tariffs[98]
- The Victorian Government policy direction does not impact our proposed changes for large business customers, and costs to accommodate these changes have not altered from our April 2015 proposal.

226. The update results in a total of $2.38m; given this is within $70k of the step change approved in the preliminary decision we maintain that $2.45m is an efficient step change cost in this submission.

227. We consider our submission promotes the Optimal NEO Position because our submission outlines activities and costs incurred by a prudent and efficient distribution network service provider. JEN's submission for the step change for new tariff implementation is the same as its April 2015 proposal[99] and is presented in Table 12–1.

Table 12–1: New tariff implementation step change forecast ($2015, millions)

Step change	2016	2017	2018	2019	2020	Total
New tariff implementation (our April 2015 proposal) and this submission	1.23	0.47	0.25	0.25	0.25	2.45
New tariff implementation (review in the context of an opt-in tariff)	0.51	0.69	0.67	0.26	0.26	2.38

228. The updated annual cost build ups are provided in Table 12–2 to Table 12–6.

95 Jemena's experience from the Jemena Gas Networks (**JGN**) is that there is a strong correlation between promotional activity and direct customer interaction. For example, electronic mail and direct mail sends to customers drove spikes in traffic to our website, and advertising is strongly correlated with new connections.

96 Promotional activity is necessary to help achieve the benefits of cost reflective tariffs.

97 ACCC, *ACCC decision on Australian Postal Corporation 2015 price notification*, December 2015.

98 NER, cl 6.18.5.

99 JEN's April 2016 proposal referred to $2.46m, the difference is due to rounding error.

Table 12–2: 2016 cost build-up ($2014, $dollars)

Change	Service	Volume	Period (Months)	Work Days	FTE	Cost
1	Service desk calls	1,500	6	126	0.21	12,353
2	Service desk emails	1,500	6	126	0.35	20,588
3	Increase in Tariff changes	500	6	126	0.12	6,863
4	Billing emails	300	6	126	0.07	4,118
5	Billing disputes	300	6	126	0.06	3,294
6	Customer relations enquiries	800	6	126	0.28	16,471
7	Retailer communications - KVA		1	20	1	9,450
8	Retailer communications - cost reflective tariffs		3	60	1	28,350
9	Customer engagement		6	60	1	56,700
10	Business -UAT		2	42	3	59,535
11	Process changes - Work instructions & Call scripting		2	42	1	19,845
12	Mail out cost	2,000				2,000
13	Mail out - preparation/content			5	1	2,363
14	Business Analyst		6	126	1	189,000
15	Business SME backfill		6	126	1	59,535
16	Reporting frame work			10	1	4,725
	Total					**$495,189**

Table 12–3: 2017 cost build-up ($2014, $dollars)

Change	Services	Volume	Period (Months)	Work Days	FTE	Cost
1	Service desk calls	500	12	252	0.03	4,118
2	Service desk emails	400	12	252	0.05	5,490
3	Increase in Tariff changes	500	12	252	0.06	6,863
4	Billing emails	250	12	252	0.03	3,431
5	Billing disputes	250	12	252	0.02	2,745
6	Customer relations enquiries	100	12	252	0.02	2,059
7	Retailer communications - KVA		1	21	1	9,923
8	Retailer communications - cost reflective tariffs		3	60	1	28,350
9	Customer engagement		6	60	1	56,700
10	Business -UAT		2	42	3	59,535

Change	Services	Volume	Period (Months)	Work Days	FTE	Cost
11	Process changes - Work instructions & Call scripting		2	42	1	19,845
12	Mail out cost	336,295				336,295
13	Mail out - preparation/content			20	1	9,450
14	Reporting frame work			10	1	4,725
15	Business Analyst		3	63	1	94,500
16	Business SME backfill		3	63	1	29,768
	Total					**$673,796**

Table 12–4: 2018 cost build-up ($2014, $dollars)

Change	Services	Volume	Period (Months)	Work Days	FTE	Cost
1	Service desk calls	5,000	12	252	0.35	41,176
2	Service desk emails	3,500	12	252	0.40	48,039
3	Increase in Tariff changes	2,500	12	252	0.29	34,314
4	Billing emails	1,500	12	252	0.17	20,588
5	Billing disputes	700	12	252	0.06	7,686
6	Customer relations enquiries	1,000	12	252	0.17	20,588
7	Retailer communications - cost reflective tariffs		3	60	1	28,350
8	Customer engagement		6	60	1	56,700
9	Business -UAT		2	42	1	19,845
10	Process changes - Work instructions & Call scripting		2	42	1	19,845
11	Mail out cost	342,748				342,748
12	Mail out - preparation/content			20	1	9,450
13	Reporting			10	1	4,725
	Total					**$654,055**

Table 12–5: 2019 cost build-up ($2014, $dollars)

Change	Services	Volume	Period (Months)	Work Days	FTE	Cost
1	Service desk calls	5,000	12	252	0.35	41,176
2	Service desk emails	3,500	12	252	0.40	48,039
3	Increase in Tariff changes	2,500	12	252	0.29	34,314

Change	Services	Volume	Period (Months)	Work Days	FTE	Cost
4	Billing emails	1,500	12	252	0.17	20,588
5	Billing disputes	700	12	252	0.06	7,686
6	Customer relations enquiries	1,000	12	252	0.17	20,588
7	Retailer communications - cost reflective tariffs		3	60	1	28,350
9	Business -UAT		2	42	1	19,845
10	Process changes - Work instructions & Call scripting		2	42	1	19,845
11	Mail out cost	6,496				6,496
12	Mail out - preparation/content			5	1	2,363
	Total					**$249,291**

Table 12–6: 2020 cost build-up ($2014, $dollars)

Change	Services	Volume	Period (Months)	Work Days	FTE	Cost
1	Service desk calls	5,000	12	252	0.35	41,176
2	Service desk emails	3,500	12	252	0.40	48,039
3	Increase in Tariff changes	2,500	12	252	0.29	34,314
4	Billing emails	1,500	12	252	0.17	20,588
5	Billing disputes	700	12	252	0.06	7,686
6	Customer relations enquiries	1,000	12	252	0.17	20,588
7	Retailer communications - cost reflective tariffs		3	60	1	28,350
9	Business -UAT		2	42	1	19,845
10	Process changes - Work instructions & Call scripting		2	42	1	19,845
11	Mail out cost	6,353				6,353
12	Mail out - preparation/content			5	1	2,363
	Total					**$249,148**

13. REGULATORY INFORMATION NOTICE REPORTING

13.1 JEN'S JULY 2015 SUBMISSION

229. JEN proposed a step change in opex to enable it to comply with the AER's regulatory information notice (**RIN**) reporting requirements. The step change relates to JEN's regulatory obligation to report information to the AER through the annual, economic benchmarking (**EB**) and category analysis (**CA**) RIN. Our proposal is outlined in July 2015 submission.

230. The July 2015 submission, outlined $19.65 million of opex that we expected to incur to comply with the RINs over the 2016 regulatory period. In particular, the costs relate to the requirement in the RINs that the information be assured as Actual Information rather than Estimated Information. Further, we outlined the new processes for data collection and the management and reporting to achieve this additional assurance standard of compliance. The definition of Actual Information and Estimated Information is contained in the RINs.

231. JEN considered four options to meet the requirements to provide Actual Information:

1. Make no change—this is not considered an option for JEN because JEN would be non-compliant with the RIN and be subject to penalties and proceedings under the NEL
2. Put in place the policies, procedures, systems and conduct necessary training to provide the required Actual Information in the timeframes required—this option would best meet the requirements set out the RINs and ensure compliance
3. Put in place the policies, procedures, systems and conduct necessary training to provide the required Actual Information but exclude providing actual data for areas where it is unlikely that providing actual data would meet the net benefit test—taking a pragmatic approach to compliance
4. Put in place the policies, procedures, systems and conduct necessary training to provide some, but not all of the obligations—allow the AER and JEN to determine an optimal mix of Actual Information and Estimated Information to promote the Optimal NEO Position.

232. Our July 2015 submission reflected the activities and costs required to achieve option 3.

13.2 PRELIMINARY DECISION

233. The preliminary decision did not approve a step change for RIN reporting. This is not withstanding that the AER acknowledged that the new RIN reporting requirements is a new regulatory obligation that may give rise to a justifiable step change.[100]

234. However, the AER determined that there was not sufficient material to form a view as to the quantum of an efficient opex step change. The AER indicated that the total cost proposed by JEN is not reasonable compared to JEN's total opex and that some of the components of the step changes are not reasonable. The AER outlined a number of particular concerns. In summary:

- JEN has taken too conservative approach in assessing what is required by Actual Information[101]

[100] AER, *Preliminary decision Jemena distribution determination 2016-2020, Attachment 7 – Operating expenditure*, October 2015, p 7-81.

[101] ibid, p 7-79.

- Some of the costs appear to relate to information that JEN already provides[102]
- There is no evidence that efficiencies have been factored in for similar information in both RINs[103]
- The audit costs are high given the RINs are already subject to audit[104]
- JEN has not justified the level of monitoring and training costs.[105]

235. The AER invited JEN to reconsider the requested step change and the information and evidence provided in support and present a better case for consideration in the revocation and substitution of the preliminary decision.[106]

236. In addition:

- The AER stated that it expected the cost of complying with the RIN would be consistent across the businesses and referred to some businesses that have not proposed increases
- The AER formed the view that because the businesses did not provide cost estimates when the AER consulted on the RINs, it was reasonable to assume that the costs would not be material
- The AER also considers that the businesses have taken a narrow and risk adverse interpretation of Actual Information.

13.3 JEN'S RESPONSE AND THIS SUBMISSION

237. We welcome the preliminary decision's recognition that the incremental RIN obligation—to report JEN's Actual Information—will likely result in a step change. We also note that the exclusion in the 2011 regulatory period EBBS further supports the need for a step change.

238. However, we do not agree with the preliminary decision on the step change for RIN reporting. However, we agree that RIN reporting is a new obligation that may give rise to a step change. We also understand that the AER has concerns with the level of the assumptions adopted in forecasting the cost of this step change. We have modified our position and have addressed the particular concerns of the AER in relation to the potential duplication of costs, expected recurrent versus one off costs, efficiencies in collecting data across RINs, increased audit costs and particular cost item assumptions.

239. We are not seeking to reduce the amount of information provided to the AER, nor reduce the accuracy of the information, but rather wish to avoid the additional compliance costs to JEN and our customers. United Energy, Citipower, Powercor and JEN have all identified that the new requirement to provide Actual Information is the driver for the cost increase (see section 13.3.1). Therefore, it is likely that significantly greater costs could be avoided if a revised definition could apply to all the distribution network service providers.

240. Based on the definition of Actual Information in the RIN, JEN confirms that its submission presented here promotes the Optimal NEO Position because it reflects JEN's prudent and efficient costs of complying with the new RIN reporting obligations.

[102] Ibid, p 7-80.

[103] Ibid, p 7-80.

[104] Ibid, p 7-80.

[105] Ibid, p 7-80.

[106] Ibid, p. 7-81.

13.3.1 DRIVER OF ADDITIONAL COST IS THE INCREASE IN THE REQUIREMENT FOR INFORMATION TO MEET THE DEFINITION OF ACTUAL INFORMATION

241. JEN is required to provide information to the AER in response to a RIN.

242. The RIN sets out requirements for how JEN is to prepare and maintain the information as well as requirements for audit and assurance. The RIN provides definitions of when the information provided is to be Estimated Information or Actual Information.

243. From 2015, JEN will be required to provide the EB RIN in the form of Actual Information and from 2016; JEN will be required to provide CA RIN in the form of Actual Information except where the RIN specifically provides for the information to be Estimated Information.

244. The increase in the amount of information that must meet the definition of Actual Information results in an increase in the efficient cost of complying with the RIN reporting requirements.

245. There are significant changes required relating to new processes for data collection, the management and reporting to achieve the requirement to provide Actual Information and the associated assurance standard of compliance. The definitions of Actual Information and Estimated Information are contained in the RIN and reproduced in Box-13-1.

Box 13-1: Definitions contained in the RIN[107]

Actual Information

- Information presented in response to the Notice whose presentation is Materially dependent on information recorded in the Distribution Network Service Provider's (**DNSP**) historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the Notice is not contingent on judgments and assumptions for which there are valid alternatives, which could lead to a Materially different presentation in the response to the Notice. 'Accounting records' include trial balances, the general ledger, subsidiary accounting ledgers, journal entries and documentation to support journal entries. Actual financial information may include accounting estimates, such as accruals and provisions, and any adjustments made to the accounting records to populate DNSP's regulatory accounts and responses to the *Notice*. 'Records used in the normal course of business', for the purposes of non-financial information, includes asset registers, geographical information systems, outage analysis systems, and so on.

Estimated Information

- Information presented in response to the Notice whose presentation is not Materially dependent on information recorded in DNSP's historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the Notice is contingent on judgments and assumptions for which there are valid alternatives, which could lead to a Materially different presentation in the response to the Notice.

246. On the basis of the definitions presented in Box 13-1, Table 13–1 presents the percentage of information currently meeting the definition of Actual Information.

107 KPMG, *Letter outlining the definition of actual information*, 17 December 2015, p 3. [see Attachment 8-10 to this submission]

Table 13–1: Information meeting the definitions required under RIN reporting in 2014

Percentage of information meeting definition of Actual Information and Estimated Information in 2014	EB RIN		CA RIN	
	Actual Information	Estimated Information	Actual Information	Estimated Information
Financial	32%	68%	10%	90%
Non-financial	85%	15%	77%	23%

Source: KPMG, Letter outlining the definition of Actual Information, 17 December 2015, p. 17

247. JEN sought advice from KPMG (its external auditors) on the issues associated with the new compliance requirement and the potential impact on JEN of achieving compliance. KPMG provided a letter to JEN outlining the substance of the issues involved and the potential impact on the reporting activities and assurance. This letter is provided in Attachment 8-10 of this submission.

248. Essentially, the additional activities and costs stem from the requirement to meet two conditions of the definition of Actual Information which both need to be satisfied to fulfil the definition. They require that the Actual Information is:

- materially dependent on historical records that are used in the normal course of business (Condition 1); and
- not contingent on judgements and assumptions for which there are valid alternatives that could lead to a materially different presentation (Condition 2).

249. These two conditions are independent. Any requirement for judgement or an assumption is independent of whether the resulting data is recorded in historical records used in the normal course of business.[108]

250. The challenge that Condition 1 poses for JEN is that the AER's definition of Actual Information requires JEN to modify its data capture processes and associated data accounting controls such that the capture, recording and quality assurance of all non-financial information and at least all unadjusted financial information (if not all financial information), required for RIN reporting, becomes part of the normal course of business. However, until this can be achieved, JEN could be at risk of being unable to report in its responses to the RINs, information that is exclusively Actual Information.[109] The changes required to approaches and procedures to achieve the Actual Information definition are significant and outlined later in section 13.3.2.

251. Condition 2 indicates that although it is envisaged that information is prepared or presented on an estimated basis through the use of judgements or estimates. However, the information can only be Actual Information if there is a single set of valid assumptions and judgements and no other valid alternative judgments and assumptions could lead to a materially different presentation. This could preclude JEN from reporting other more valid information in certain circumstances.[110]

108 KPMG, *Letter outlining the definition of actual information*, 17 December 2015, p 3. [see Attachment 8-10 to this submission].

109 Ibid, p 6.

110 Ibid, p 7.

252. Box 13-2 illustrates the issues associated with the requirements to report Actual Information as outlined in the KPMG letter.[111]

Box 13-2: The requirement to report only Actual Information

CONDITION 1
Materially dependent on historical records?

CONDITION 2		YES	NO
Contingent on judgements and assumptions for which ***there are no valid alternatives*** *which could lead to a materially different presentation?*	***YES***	**RIN DEFINITION OF "ACTUAL INFORMATION"**	**NO RIN GUIDANCE**
Contingent on judgements and assumptions for which ***there are valid alternatives*** *which could lead to a materially different presentation?*	***YES***	**NO RIN GUIDANCE**	**RIN DEFINITION OF "ESTIMATED INFORMATION"**

This diagram illustrates the relationships between Conditions 1 and 2 and the RINs' definitions of "Actual Information" and Estimated Information".

This diagram also illustrates that the RIN definition of Actual Information (see Appendix A):

- requires only information that satisfies both of Conditions 1 and 2, to be reported;
- excludes Jemena from reporting information that may meet one but not both of Conditions 1 and 2, as well as excluding Jemena from reporting Estimated Information that meets neither of Conditions 1 and 2; and
- permits information that is contingent on judgements and assumptions to be reported as Actual Information, provided that:
  - there are no valid alternatives for those judgements and assumptions, which could lead to a materially different presentation; and

the information can be drawn from historical records that are used in the normal course of business.

253. Although, the AER provides a discussion of the interpretation of the definition for Actual Information[112], it is inconsistent with the definition in the RIN. For example, the RIN definition of Actual Information requires that the information is materially dependent on historical records and not contingent on judgements and assumptions for which there are valid alternatives. However, section C.4.13 of the preliminary decision indicates that Actual

[111] Attachment 8-10 - KPMG, Letter outlining the definition of "Actual Information", 17 December 2015, p 8.

[112] AER, *Preliminary decision Jemena distribution determination 2016-20, Attachment 7 - Operating expenditure,* October 2015, s. C.4.13.

Information could include an assessment of the number of trees derived from a reasonable sample. A reasonable sample relies on judgement to identify the sample. The AER further indicates that the information about the number of trees could come from third parties. Information from third parties is not materially dependent on historical records used in the normal course of business unless changes are implemented to enable the capture of this data as a business record. Therefore, the clarification provided by the AER seems to directly contradict the definition of Actual Information in the RIN.

254. The AER also recognises that JEN may have already been using a sampling method to comply with previous RIN responses. This may be the case; however our proposed step change reflects the cost of complying with the new requirement to provide Actual Information—not the costs of complying with past RIN obligations that have included a mix of Actual Information and Estimated Information.

255. Therefore, the additional guidance provided in the preliminary decision provides little, if any, additional certainty and, to be prudent, JEN must closely follow the definition of Actual Information provided in the RINs. This is because, the AER's guidance:

- Appears to recognise that Actual Information may include estimates
- Does not address a key criterion of Condition 2 that Actual Information must not be based on estimates for which valid alternatives exist
- Continues to suggest that the extent of information extracted from records not used in the normal course of business, should not to be material
- Acknowledges but leaves open the breadth of potential interpretation of Actual Information.[113]

256. The substance of the definitions contained in the RIN is inconsistent with generally accepted accounting principles and concepts. Further, the requirement that no value alternative judgements, estimates and assumptions exist that could lead to materially different presentations is inconsistent with generally accepted concepts recognised and embodied in Australian Accounting standards (which do not preclude the use of judgements, estimates and assumptions).[114]

257. KPMG identifies in its letter some potential alternatives that could mitigate compliance risk and provide improved basis for defining information quality. In particular, KPMG outline a principle based reporting framework which would provide an outcome based framework for setting standards of quality for the information, address risks that arise under the current definitions and uncertainty about the interpretation, remove the potential impasse and non-compliance and provide consistency with generally accepted accounting principles and concepts and accounting standards. This approach would complement rather than avoid the new RIN requirements.[115]

258. Nevertheless, KPMG indicated that:

> "*if Jemena is unable to provide Actual information where it is required to do so, it may not be in compliance with the RIN requirements. We will consider the impact of this on our audit/review reports by having regard to the magnitude of non-compliance and potentially issue a qualified audit or review report, if the non-compliance is assessed as material to the overall RIN response*[116].

259. It is important to us that we are not issued a qualified review report for non-compliance. It is for this reason we commissioned the independent reviews of our proposed systems and process changes. They allowed us to

113 Attachment 8-10 - KPMG, Letter outlining the definition of "Actual Information", 17 December 2015, p 10.

114 Ibid, p 11.

115 Ibid, p 12.

116 Ibid, p 16.

robustly challenge our own forecast, by assessing the perceived necessity of system and process changes. In addition, it allowed us, as a prudent and efficient operator, to assess the 'reasonableness' of the proposed changes to provide RIN compliant Actual Information.

13.3.2 THE JOURNEY SO FAR

260. JEN was notified in June 2015[117] that the RIN requirements relating to the reporting of Actual Information and Estimated Information for the RIN's was to change. At that time, JEN sought to:

- Identify and prepare a submission on the expected costs that might impact on JEN during the 2016 regulatory period to ensure that it was included in our 13 July 2015 submission[118] as an opex step change so that JEN could recover the efficient costs of complying with its new obligation
- Sought a comprehensive review of the measures required to ensure that the information that had previously been provided as Estimated Information could now be provided as Actual Information. PB undertook an extensive review of each item and category and provided advice on what would be required to meet the compliance requirement.

261. The report from PB had not been finalised at the time of making the July 2015 submission. However, work has continued to review the measures, activities and costs associated with achieving the new RIN requirements. The Final Report was received by JEN on 22 October 2015.

262. JEN met with AER staff in August 2015 to share JEN's understanding of the drivers and implications of the change to the RIN requirements and seek to understand the value of the information to the AER. As outlined at the meeting, JEN's Board and management expect that investment of the significance required to achieve the RIN reporting requirements is supported with sufficient substance to enable the investment decision to be made. Therefore, JEN continued to analyse the requirements, options and costs to comply.

263. Prior to the July 2015 submission, JEN consulted with the AER to confirm our understanding of the RIN Reporting requirements. At that time, the AER's Andrew Ley confirmed that:

> "*NSPs must provide Actual information, as defined in the [EB and CA RIN]. This applies to all variables except those that exempted in the [EB and CA] RIN's instructions and definitions*". [119]

264. JEN understood and acknowledged it was therefore obliged to change its systems and processes to best meet these new RIN requirements.

265. Between the time of the AER's advice and the date of our July 2015 submission, being a period of only seven weeks, JEN was obliged to make high level assessments of the changes required to systems, processes and people to be compliant. Recognising the financial and non-financial Actual Information required for the RINs is far from straightforward.

266. Since our July 2015 submission on reporting of Actual Information, we have continued to review the requirements and activities to comply. We have proactively sought independent advice regarding the adequacy of our proposed changes to systems and processes to satisfy the RIN requirements. The firms engaged considered whether the bulk of the RIN information was captured as well as whether it would allow JEN to be considered materially compliant by providing Actual Information.

117 E-mail from AER staff to JEN staff, 10 April 2015 and 10 June 2015.

118 E-mail from JEN staff to AER staff, 13 July 2015.

119 E-mail from AER staff to JEN staff, 10 April 2015 and 10 June 2015.

13.3.3 THE APPROACH TO ESTIMATING THE EFFICIENT COSTS OF COMPLIANCE

267. The main difficulty for JEN is that the requirement for RIN data to be Actual Information means that it must be drawn substantially from business systems and cannot incorporate judgement for which there are valid alternatives.

268. JEN sought a review of the measures required to transition from Estimated Information to Actual Information from Parsons Brinkerhoff (**PB**).[120]

269. Significant changes are required to JEN's systems, processes, staff capability and culture to ensure all the RIN data is captured (benchmarking and category) and an 'automated' approach is adopted to produce the data. The PB report presents, for each information requirement, the current status of reported information and the activities required to achieve Actual Information. This report has formed the basis for JEN's RIN reporting cost estimate as discussed in the following sections.

270. JEN has revisited its July 2015 submission and used the results of a review by PB to assess our proposed measures required to transition from Estimated Information to Actual Information. In addition, JEN sought advice from KPMG on the findings of the PB report and to ensure our external auditors could support the proposed measures to deliver Actual Information for assurance purposes.

271. Therefore, JEN has refined the solution given the further detail which has allowed the responsible staff and management across the affected business units to be more specific in their cost calculations. This has seen a sizeable decrease in our cost estimates.

272. JEN recognises that full and literal compliance is not practical or possible, so our submission is centred on extending capability to deliver compliance to the maximum extent possible and consider options where Actual Information is not attainable or cannot be collected at a cost that fits within the social net benefit objective.

273. Having recently completed a replacement of its legacy Enterprise Resource Planning (**ERP**) solution as a part of the normal system lifecycle management, JEN has significantly improved its ability to categorise and manage the data collected, especially with the introduction of the new ERP Project Management and Works Management modules. Further work to extend this capability and support the full and proper use of our SAP solution also aligns to better compliance with the CA RIN. JEN plans to become substantively compliant with the AER's RIN reporting requirements over an 18 month period.

274. Whilst JEN's ERP replacement in the 2011 regulatory period provides a strong foundation for the RIN reporting cycle, it needs a number of adjustments to facilitate the data entry at the specified level of detail for the RINs. In addition, it should be noted that on either side of the new ERP are legacy processes that, unless addressed, will inhibit the ability to collect and report RIN data, regardless of the data entry points created in SAP.

275. This is in large part due to the level of detail required by the RINs being so granular, additional paper forms will be required to be completed by field services staff. Current practice requires field staff to select from a number of applicable forms when completing a job. Staff are required to manually record time against each job and each relevant activity for that job.

276. By using 'at the source' data entry systems, the capture of 'Actual Information' data is more efficient, rather than follow up data collection (and often correction) during ex-post audits or downstream data entry.

277. To be considered compliant, more accurate details about each job is required. JEN's SAP solution has the capacity to record this data, although currently there is no means of efficiently entering the additional data. Provided data entry screens are updated to allow the data capture, reports can be created in compliance with

[120] Attachment 8-12 – Parsons Brinckerhoff, *Jemena Electricity Network Conversion of Regulatory Information Notice information to actual*, October 2015.

RIN reporting requirements. However, without automated solutions to issue complete work orders with relevant activity codes related to the job, the flexibility is limited by the number of paper forms the field services crew can take on.

278. The field mobility project, upon which this project is dependent, will make data collection simpler and efficient, allowing JEN to target and capture more detailed information in a controlled manner, leading to better benchmarking information for the AER.

279. Regardless of the method used, the additional and more detailed data capture required for the new RIN templates creates a substantial change impact on the business—whether it is electronically captured via field mobility or manually via additional forms, particularly for field services staff. For field crew, time spent on 'administrative' activities is viewed as undesirable, with no direct link to the work they do. JEN's field services staff have on average 16 years of service, using largely the same systems and processes for that time. Any change to method of capture or, detail and stringency of capture, results in a significant change to work methods of field services staff that must be managed so as not to impact our customers.

280. To understand the potential scale of the change, an assessment of the modifications required to move to Actual Information data was the foundation of a review of the 'basis of preparation' of each RIN and the record of whether the data was deemed an estimate or Actual Information. The gap between the RIN reporting requirement and the current available information to meet that requirement was assessed by reviewing each category within each RIN and making a determination as to the cause of the estimate— that is, whether the estimate is caused by a business process issue that does not mandate the capture of specific information, or, a technological issue, such as a data field or system does not exist to capture and record the necessary information.

13.3.4 ACTIVITIES REQUIRED TO PRODUCE ACTUAL INFORMATION

281. The process JEN undertook to estimate the costs was:

- Identify the data and information that can currently be defined as Actual Information and Estimated Information
- Where information is identified as Estimated Information, identify the activities required to produce Actual Information
- For each activity, identify whether it can be undertaken by internal or external labour or requires the purchase of materials or equipment
- Estimate the cost for each activity
- Review the estimates for consistency and deliverability
- Develop a business case to capture assumptions, activities and estimates and identify and compare options to achieve compliance with the RIN requirements
- Leadership endorse the business case.

282. Based on the PB report, JEN sought to understand the activities required to deliver the Actual Information. The PB report considers each item of the RIN and CA RIN requirements and recommends for the measures required to deliver Actual Information, JEN allocated a project manager to consider each required measure and estimate the activities and costs associated with each.

283. JEN's approach was to capture each activity for each RIN (benchmarking and category analysis). The activities required to comply with the RIN requirements are identified as:

- **Project management** – this includes the provision of a resource to establish the governance and planning required to manage the project, ensure that the business requirements are delivered, ensure that resources are properly allocated and engaged on the project, communication about progress and activities is timely and accurate, costs are tracked and managed accordingly and regular reporting and monitoring occurs
- **System changes and enhancements**[121] – this category of costs include analysis of IT systems to understand the availability of the fields to capture data, project management of the IT delivery component, development of software architecture, definition of the interface requirements of the systems, upgrades to SAP, GIS and VMS, development of the system including programming requirements, testing and deployment
- **Data capture** – this category of activity encompasses the time associated with employees and contractors capturing the additional information, recording it in the systems and converting it in to the form required. For example, the required granular breakdown of costs, tree volume data, route line length and standard vehicle access
- **Change management** – ensuring that proper change management strategies are adopted and implemented to support the successful implementation of the desired changes in processes
- **Training** – these costs relate to developing, planning and preparing training modules including tailoring to specific business units and field delivery, implementing and delivering the training and follow up training to ensure effectiveness
- **Business improvement reporting** – these costs are associated with developing and implementing the reporting requirements for work feeding in to the RIN and presenting results to the management and leadership teams
- **Process change** – these costs are associated with the IT support required to generate the data for the first year and ensure the system changes and reports are generated as expected. These costs will only be incurred in the first year to understand the process required to extract data and populate Actual Information data in RINs
- **Audit cost** – the additional costs associated with increasing the scope of external audit
- **Support subsequent to implementation** – ongoing support costs for the system changes and enhancements
- **Monitoring** – required to ensure that the new system and process changes are being implemented and data is being captured in the field, the information is being recorded in SAP, GIS and VMS and monthly reports are being prepared in the RIN format, ongoing training needs are being identified and liaison across departments and review of third party performance against requirements.

[121] There costs are categorised as capex under Australian accounting standards and have been included in the revised capex forecast. The costs ($2.5m) are not included in the opex step change forecast.

284. Table 13–2 presents a summary of these costs by year for CA RIN and EB RIN.

Table 13–2: Activity and opex for each activity, 5 years ($2015)

($2015)		RIN B and RIN C		
Function	**Cost category**	**Non-recurrent**	**Recurrent (2017-20)**	**Total**
Project Management	Opex	653,500	0	653,500
System changes	Capex	2,122,900	0	2,122,900
Data capture	Opex	1,129,936	0	1,129,936
Change management	Opex	568,400	0	568,400
Training	Opex	775,424	0	775,424
Business improvement reporting	Opex	68,000	0	68,000
Process change	Opex	189,400	0	189,400
Audit costs	Opex	0	857,438	857,438
Support	Opex	194,400	0	194,400
Monitoring	Opex	0	1,440,000	1,440,000
Totex		**5,701,960**	**2,297,438**	**7,999,397**
Opex		3,579,060	2,297,438	5,876,497
Capex		2,122,900	0	2,122,900
Totex		**5,701,960**	**2,297,438**	**7,999,397**

Source: Attachment 8-11 of this submission, Appendix A1.

13.3.4.1 Nature of costs

285. JEN sought to ensure that the project activities were properly characterised as capital or operating expense consistent with Australian Accounting standards. This review identified that the system changes and enhancement expenditure was properly treated as a capital expense.

286. Table 13–3 presents the capex and opex associated with compliance with RIN requirements.

Table 13–3: Capex and opex associated with compliance with RIN requirements ($2015, million)

	Capex	Opex	Total
EB RIN	0.23	0.80	1.02
CA RIN	1.90	5.08	6.97
Total	**2.12**	**5.88**	**8.00**

Source: Attachment 8-11 of this submission, Appendix A1.

287. The estimates of the time required for each activity reflects the views of the individuals with roles and responsibilities for undertaking each task. The system changes and enhancement task were provided to the IT business unit to seek a cost estimate in line with JEN's project estimation governance processes. This process identified that there would be considerable one-off implementation costs to be incurred in 2016 but once these

activities were implemented, the ongoing annual costs would be significantly less with some of the ongoing costs being incorporated into business as usual roles and responsibilities resulting in no net increase in costs.

288. Table 13–4 presents the one off and ongoing costs associated with compliance with RIN requirements.

Table 13–4: One-off and ongoing opex required to comply with RIN requirements ($2015, million)

RIN	Non-recurrent costs	Recurrent costs	Total
EB RIN	0.75	0.01	0.80
CA RIN	2.83	0.56	5.08
Total	**3.58**	**0.57**	**5.88**

Source: Attachment 8-11 of this submission, Appendix A1.

13.3.4.2 Review of activities and costs

289. Once the cost estimates were developed for EB RIN and CA RIN, they were captured in a spreadsheet model. The model was reviewed by the asset management, finance, IT and regulatory business units, and management to test that the activities identified were a reasonable representation of what would be required by each department, would be expected to achieve compliance and could be delivered by the relevant department in the time lines identified.

290. This process consisted of a series of meetings and individual review of the information captured to support the activities and cost estimates. The main changes that occurred through this process were consideration of the incremental audit requirements, the need for dedicated project director and ongoing monitoring requirements. In addition, during this process it was identified that there was some RIN requirements where JEN will face challenges as a result of the activities and processes underway to achieve compliance which are not yet completed. JEN will seek to work with the AER to identify a satisfactory outcome in relation to these issues and may require the granting of an exemption. The forecast expenditure and opex step change do not include any costs associated with providing Actual Information for the items in Table 13–5.

291. A summary of the items where compliance will be challenging at least initially is presented in Table 13–5.

Table 13–5: RIN Reporting requirements where an agreed approach to compliance may be required

RIN	Item	Issue
EB RIN – Item 1	Energy not supplied (planned or unplanned) - DQS0201 and DQS0202	RIN allows this information to be estimated.
EB RIN – Item 2	Table 3.3.4.2 : Asset Lives - estimated residual service life	JEN is unable to provide data (asset installation dates) as some assets are so old that their installation dates are not recorded.
EB RIN – Item 3	DOPSD0302 : Average power factor conversion for low voltage distribution lines	Request AER for exemption and allow JEN to report this variable as an estimate. The cost to produce Actual Information is significant (close to $50m) as it would require installing power quality meters on 20% of JEN's distribution substations to record kW and KVA data for the whole year (1250 meters x $40,000 per meter (with communications) = $50,000,000).

RIN	Item	Issue
CA RIN – Item 1	Mean and Standard deviation – Table 5.2 (Asset Age profile)	RIN allows this information to be estimated.
CA RIN – Item 2	Table 5.2 : Asset Age Profile across various asset categories	JEN is unable to provide this data (asset installation dates) as some assets are so old that their installation dates are not recorded.
CA RIN – Item 3	Table 5.4 MD & Utilisation Level (SA zone substation)	JEN will seek to agree with the AER that this data remain estimated because it would require more meters to be installed or significant improvement in availability of smart meter data to get actual data at a high capital cost.
CA RIN –Item 4	Table 5.4 MD & Utilisation Level (Sub transmission Substation – Raw Adjusted MD –abnormal conditions) Table 5.4 MD & Utilisation Level (Zone Substation – Raw Adjusted MD – abnormal conditions)	Given that the load transfer is estimated, the information must be considered as Estimated Information. Direct measurement of the load transfer would require either installation of meters on every switch/isolator on JEN network or significant improvement in availability of smart meter data to get actual data, and lots of manual processing of data. This will be a significant cost. JEN will seek agreement with the AER to be allowed to continue to report the variables as Estimated Information.

13.3.5 RIN REPORTING BUSINESS CASE

292. To inform JEN and the AER in relation to the activities and costs associated with complying with the new RIN requirements, JEN has developed a Business Case (Attachment 8-11 of this submission) for the RIN compliance program of work.

293. The purpose of Business Case is to analyse at a high level, the current state of JEN's processes and systems with respect to their ability to meet the AER's RIN requirements, identify and evaluate alternative options of meeting these requirements and recommend the most feasible option in line with the AER Expenditure Assessment Guidelines.

294. The Business Case tests the activities and costs to be incurred to comply with the RIN requirement to provide Actual Information with other compliance options. In this business case, four options have been carefully considered and are presented in Table 13–6.

Table 13–6: Description of options considered in the RIN reporting business case

Option	Description
Option 1: Do Nothing	The 'Do Nothing' option involves continuing with current systems and processes and results in JEN not being able to meet all RIN reporting requirements, thus being non-complaint.
Option 2: Non-systems based compliance	Non-systems based compliance involves enhancing current business processes (within existing system capabilities) and an increased level of RIN dedicated Asset Accountants and Data Analysts resources to capture an increased level of granularity required to meet RIN reporting requirements and be nominally compliant with AER RIN obligations.
Option 3: Transition to system enabled RIN reporting with interim workaround	Option 3 is considered a pathway to system enabled RIN reporting compliance. This option involves one-off capital expenditure to extend the configuration of the current SAP system to enable an integrated approach to, reviewing and redesigning business processes which will aid long term efficiency and permit the system based capture of data required to comply with the

Option	Description
	AER RIN notices. This option also considers an opex step change (i.e. increased FTEs and training) for an interim solution required to facilitate increased RIN compliance during the period where the RIN system capability is not yet available and is in the process of being delivered.
Option 4: Transition to system enabled RIN reporting with no interim workaround	Option 4 is a variation of Option 3, but with no proposed interim solution whereby JEN takes a staged approach to delivery, focussing on compliance with the Economic Benchmarking RIN by December 2016 and the Category Analysis RIN by July 2017.

Source: Attachment 8-11: RIN reporting business case, Executive summary.

295. All the options (bar Option 1) are designed to facilitate JEN's compliance with the RIN reporting requirements, exploring various options such as relying wholly on a manual solution, a system only solution and an option that proposes manual processes until such time as all systems (including those projects upon which RIN reporting is highly dependent) are enabled. Further flexibility can be built into the options but will affect cost and duration until compliance.

296. The core difference between the options is that Option 2 "Non Systems Based Compliance" approach is manual, with no changes to systems and relies on capturing data manually via paperwork captured in the field and entered into uncontrolled formats such as Excel spreadsheets where existing systems do not have the necessary screens to enter the data. Compliance becomes more difficult to manage as well as more resource intensive but does not involve any significant change to existing business processes and therefore avoids (but does not eliminate) significant change management costs.

297. The other options extend the current systems capability to allow data capture via enhanced data entry screens and development of reports capable of collating and linking the data required in the RIN reports. Compliance can be achieved in a phased manner or, from the start, depending on the approach chosen. The options are presented in more detail in Attachment 8-11 of this submission. A summary of the Net Present Cost (**NPC**) and risk assessment of the options is presented in Table 13–7. The Business Case also provides further information on the approach to the risk assessment. The primary risk assessed is the risk of non-compliance.

Table 13–7: Summary of business case assessment, 5 years ($2015, million)

Option	1. Do Nothing	2. Non- system based compliance	3. Transition to system enabled RIN reporting with interim workaround	4. Transition to system enabled RIN reporting with no interim workaround
Non-Recurrent capex ($m)	-	-	2.12	2.12
Non-Recurrent opex ($m)	-	0.50	6.82	3.00
Recurrent opex ($m)	-	2.21	0.57	0.57
NPC ($m) (5 years)	-	9.60	11.31	7.49
Inherent risk	Extreme	High	Significant	Moderate
Residual risk	High	Significant	Moderate	Low
Advantages / Disadvantages	Leaves JEN open to prosecution and significant financial penalties due to non-compliance with RIN requirements.	Completeness of data entry is increased, but there is a lack of control over quality data entry.	Completeness of data entry is enhanced by mandating completion of particular data entry fields before a record	Completeness of data entry is enhanced by mandating completion of particular data entry fields before a record

Option	1. Do Nothing	2. Non- system based compliance	3. Transition to system enabled RIN reporting with interim workaround	4. Transition to system enabled RIN reporting with no interim workaround
			can be submitted as final 'Period of 12-18 months where JEN is non-complaint.	can be submitted as final.

Source: Attachment 8-11: RIN reporting business case, Table OV-1.

298. Not surprisingly option 1 is the least cost solution. However, this will not enable JEN to comply with the RIN reporting requirements. Option 4 is the least cost option that allows JEN to be complaint with RIN obligations to the maximum extent possible.

13.3.6 RESPONSE TO THE CONCERNS OUTLINED IN THE PRELIMINARY DECISION

299. JEN has reviewed the specific concerns raised in the preliminary decision and responded to each concern below.

13.3.6.1 Interpretation of Actual Information in relation to data capture for tree span and standard vehicle access

300. The AER was concerned that JEN had taken an overly conservative approach to interpreting of the term Actual Information. JEN has responded on this issue earlier in this section and provided further explanation in Attachment 8-10[122] of this submission. However, in relation to tree volume data and standard vehicle access data that will be collected from a third party, in JEN's revised approach and cost estimate JEN has assumed that it will only require the third party to collect the data once every regulatory period and this same data will be adopted for each subsequent year of the period. These costs will be incurred in 2016 and then again in 2021. JEN will seek to forecast these additional costs as a specific cost forecast for the 2021 regulatory period.

301. This change in approach—relative to the July 2015 submission—has reduced the compliance costs for EB RIN for tree data and standard vehicle access data from $1.42m to $0.48m ($0.94m lower).

13.3.6.2 Costs associated with providing information on RAB

302. The preliminary decision expressed concerns about the additional costs associated with JEN reporting Actual Information on the assets it owns (RAB information) in the EB RIN because JEN is already required to provide its opening RAB, disposals depreciation and additions every year. JEN notes that the RAB—and changes to the RAB—reported in the EB RIN differs to the view presented in the Annual RIN and post-tax revenue model and therefore additional costs are incurred to report on a different basis.

303. The AER referred to costs of $69,000 in 2016 and $48,000 each year after that. JEN believes that the AER has referred to incorrect information in relation to these costs. JEN has revised these costs based on a more detailed understanding of the changes required to $85,000 in 2016 and $7,000 each year after that. This reduces the costs from $0.36m to $0.11m – a reduction of $0.25m. These costs relate to the resource effort to build new reports in JEN's ERP system.

[122] KPMG, *Letter outlining the definition of actual information*, 17 December 2015.

13.3.6.3 Auditing costs

304. The preliminary decision identified a concern with the increases in the level of auditing costs to $0.5m because the AER does not consider the requirement to provide Actual Information rather than estimates results in more information to be audited or that the AER requires additional auditing. As outlined earlier, JEN has been able to identify the additional activities and requirements associated with complying with the new RIN requirements and tested this with our external auditors. In this submission, JEN has identified that there will be no additional auditing costs associated with EB RIN and the audit costs for CA RIN has been revised to $0.2m per year over the 2016 regulatory period for a total cost of $0.8m.

13.3.6.4 Efficiencies not factored in to the collection of data across RINs

305. The preliminary decision was concerned that JEN may not have factored in efficiencies it might realise when collecting data that is similar across both RINs. It referred to an example where JEN may be able to obtain both sets of responses at the same time and using the same process to obtain operating environment information such as vegetation management—where $3m was identified for EB RIN and a further $1m in CA RIN for the information.

306. Since submitting the July 2015 submission more specific information on the activities required across both RIN's and has enabled JEN to more closely consider where the requirements across both RIN's can be delivered together to achieve efficiencies. Therefore, JEN has revised its cost for EB RIN from $3m to $1.7m and included no additional costs for CA RIN reporting of vegetation management costs.

13.3.6.5 Monitoring costs compared to ongoing costs

307. The preliminary decision raised concerns about the proposed $6.2m in monitoring costs for CA RIN associated with repex, augex, connections, maintenance and public lighting because it represented over 75% of the on-going costs of complying with the category analysis RINs.

308. JEN has reassessed the ongoing monitoring costs given the system changes and enhancements that it will undertake, training to instruct the workforce on requirements and change management activities to ensure adherence to the new requirements and processes for compliance. This review has resulted in a downward revision to the extent of ongoing monitoring required.

309. The ongoing monitoring tasks include:

- Monitoring that data capture in the field is performed in a timely manner
- Monitoring the accuracy of the data recorded in SAP, GIS and VMS and that the monthly reports are generated in the required RIN formats
- Monitoring the effectiveness of controls in place and evaluation of daily activities to ensure that operational data is being captured in the required detail
- Liaising with cross-functional departments to ensure systems and procedures are in place to capture, record and report data
- Monitoring and following up that third-party entities are undertaking required tasks in accordance with requirements
- Monitoring the requirements for the need to train and retrain staff.

310. In our July 2015 submission JEN proposed that these costs would be $1.24m per year from 2016. Given the nature of the system changes and enhancement and supporting training and change management, JEN considers that the ongoing monitoring should be considerably less. The ongoing monitoring costs have been reduced to $0.36m per year, a reduction of $0.88m per year or $4.4m over the 2016 regulatory period.

13.3.6.6 Project management and training

311. JEN proposed $0.5m for training under the project management cost of complying with the category analysis RIN. The preliminary decision was concerned that there was no explanation for the need for project management training in addition to the $0.9m training costs forecast for the other categories.

312. JEN had proposed $0.56m under project management associated with training and $1.42m in total for training related to CA RIN. JEN's submission has removed costs associated with training from the project management activities and revised costs for training for CA RIN to $0.76m. Training for EB RIN has also reduced to $0.12m from $0.24m.

13.3.7 NOT PROPOSED BY OTHER NETWORK SERVICE PROVIDERS

313. The preliminary decision recognised that each business is starting from a different position regarding its existing systems and data availability[123]. However, the AER indicated that it would have expected the costs associated with RIN obligations would be relatively consistent across businesses and, that because when the AER sought information on the cost of compliance when they consulted on RIN obligations they were not provided with any estimates, they considered it was reasonable to assume that the costs would not be material.[124,125]

314. However, the AER did recognise that the cost would be substantial during the consultation process,

> *During consultation we prompted NSPs to quantify the likely cost of compliance with the draft RINs, in terms of person-hours taken to provide certain information and expenditures. Many NSPs were unable to do this, however this does not detract from their view that the costs would be substantial*[126]

315. JEN notes that nearly all other Victorian electricity distribution businesses have highlighted the issues associated with the new RIN requirements to report Actual Information and the issues were also outlined by South Australian Power Networks (**SAPN**).

316. JEN is unable to comment on the IT systems and processes of other distribution service providers or the reasons why other distribution service providers' forecast of the efficient cost of complying with the new obligations in the RIN. The information capture and reporting systems and practices of other distribution service providers may differ to JEN which will impact on the activities they have or have not undertaken in prior periods or will or will not be required to be undertaken in future periods – and the efficient costs of these activities. JEN notes that the NER:

- Do not require the distribution service providers be aligned on their information capture and reporting systems and approach

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[123] AER, *Preliminary decision, Jemena distribution determination 2016 to 2020, Attachment 6 – Capital expenditure*, October 2015, p 6-103.

[124] Ibid, p 6-103.

[125] Ibid, p 6-135.

[126] AER, *Better Regulation Explanatory Statement Category, Final regulatory information notices to collect information for category analysis*, March 2014, p 11.

- Requires the AER to assess the total opex[127] for each distribution business and assessing proposed opex step changes where the efficient cost of providing services increases, for example when new obligations are imposed, is consistent with the AER's approach to assessing opex forecasts. This is supported by the AER's approach to assessing opex in its preliminary decision.[128]

317. The preliminary decision has acknowledged that the requirement to report Actual Information is a regulatory obligation that may give rise to a justifiable opex step change[129]. Further, the AER accepted that it is prudent and efficient for SAPN to incur an additional $6.4m in opex and $8.6m in capex[130] to comply with the new RIN reporting requirements. The AER considered that the additional evidence provided by SAPN [131] demonstrated that producing Actual Information data costs materially more than estimated data. The opex step change related to introducing new procedures, systems and training and ongoing internal governance and audit cost necessary to collect and confirm Actual Information rather than estimated data.[132]

318. JEN has included in this submission additional evidence[133] to demonstrate the higher costs of providing actual information rather than Estimated Information. JEN notes that the activities required that drive the additional costs are similar to those outlined by SAPN and recognised by the AER.

319. Citipower proposed additional capex to implement an automated approach to RIN compliance. Although, the AER accepted that Citipower may incur costs above those forecast by other companies in complying with the RIN, the AER rejected CitiPower's proposed RIN reporting capex on the basis that the amounts were of a sufficient magnitude to reflect prudent and efficient expenditure.[134] The AER's preliminary decision for Powercor was very similar to that for Citipower.[135]

320. A further issue raised by the AER in the Powercor preliminary decision to not approve additional capex to meet RIN requirements was that Powercor did not disclose the economic benefits of the projects. However, the distribution businesses have continued to maintain that the benefits associated with the additional reporting requirements do not outweigh the additional costs. The AER recognised this shared view of the distribution businesses in its explanatory statement:

> At the same time, we have been sensitive to NSP concerns and views the likely costs of collecting particular data are likely to be greater than the benefits of having these data.[136]

321. The AER has identified the benefits of collecting the data to be ensuring forecast expenditure is efficient and providing increased transparency and consistency in regulatory processes.[137] The AER has assessed that the benefits outweigh the costs:

127 NER, Cl 6.5.6

128 AER, *Preliminary decision, Jemena distribution determination 2016 to 2020, Attachment 7 - Operating expenditure, Jemena Preliminary decision 2016-20*, October 2015, p 7-66.

129 Ibid, p 7-81.

130 AER, *Preliminary decision, Jemena distribution determination 2016 to 2020,, Attachment 6 – Capital expenditure SA Power Networks determination 2015-2020*, October 2015, p 6-124.

131 SA Power Networks, *Revised Regulatory Proposal*, Attachment G22 SAPN_IT EAM and RIN Reporting, 3 July 2015.

132 AER, *Preliminary decision, Jemena distribution determination 2016 to 2020, Attachment 7 – Operating expenditure SA Power Networks Determination 2015-2020*, October 2015, p 7-75.

133 See Attachment 8-4 and Attachment 8-5.

134 AER, *Preliminary decision, Jemena distribution determination 2016 to 2020*, Attachment 6 – Capital expenditure Citipower Preliminary decision 2016-2020, October 2015, p 6-103.

135 Ibid, p 6-135.

136 AER, *Better Regulation Explanatory Statement Category, Final regulatory information notices to collect information for category analysis*, March 2014, p 3.

> Ultimately, however, the compliance burden of the final templates will not be insignificant and will differ across NSPs given the transition to a new, nationally consistent reporting framework, which is seen of particular significance and will be developed further over time. We are satisfied that overall this burden will be considerably outweighed by the benefits flowing from such a framework.[138]

322. JEN notes that the preliminary decision did not include an opex step change for RIN reporting for United Energy in its preliminary decision because it considered that the opex step change was linked to the additional ICT capex of $24.3m which the AER considered was required because United Energy did not make the necessary system upgrades when the systems were replaced in the 2011-2015[139] regulatory period and the estimated costs related to improving systems in line with good industry practice rather than to comply with the specific RIN reporting obligations.[140]

323. JEN maintains that the AER must consider the additional costs associated with complying with the new RIN requirements for each business taking in to consideration the circumstances of the business. The AER has recognised that the costs would differ across businesses and that the costs would not be immaterial in its prior consultation on the RIN requirements. JEN has undertaken a thorough review of the activities and costs required to comply with the new RIN requirements and regardless of whether the costs may now be found to outweigh the benefits, JEN must be able to recover the efficient costs of complying with the new obligation.

324. Further information on the comparability of DNSP changes for RIN reporting can be found in section 5.8 of Attachment 8-11 to this submission.

13.3.8 JEN'S RESPONSE AND THIS SUBMISSION

325. JEN maintains its view that there are additional costs associated with the requirement to provide information that conforms to the AER's definition of Actual Information, that these costs are material, and are consistent with the opex assessment framework for consideration of a step change in opex.

326. JEN's submission for the expenditure required to comply with the RIN reporting requirements is $8.00m for the 2016 regulatory period. $2.12m will be incorporated in to JEN's submission for capex and $5.88m is sought as an opex step change. The opex step change for RIN reporting requirements in each year of the 2016 regulatory period is presented in Table 13–8.

Table 13–8: Regulatory information reporting compliance step change forecast ($2015, millions)

Step change	2016	2017	2018	2019	2020	Total
Regulatory information reporting compliance	3.58	0.57	0.57	0.57	0.57	5.88

137 AER, *Preliminary decision, Jemena distribution determination 2016 to 2020,* Attachment 6 – Capital expenditure United Energy Preliminary decision 2016-2020, October 2015, p 6-110.

138 AER, *Better Regulation Explanatory Statement Category, Final regulatory information notices to collect information for category analysis*, March 2014, p 4.

139 AER, *Preliminary decision, Jemena distribution determination 2016 to 2020,* Attachment 7 – Operating expenditure United Energy Preliminary decision 2016-2020, October 2015, p 7-65.

140 AER, *Preliminary decision, Jemena distribution determination 2016 to 2020,* Attachment 6 – Capital expenditure United Energy Preliminary decision 2016-2020, October 2015, p 6-111.

14. INCREASED GUARANTEED SERVICE LEVEL OBLIGATIONS

14.1 JEN'S APRIL 2015 PROPOSAL

327. JEN did not propose a step change for the costs associated with the changes in the Victorian Jurisdictional Guaranteed Service Level (**GSL**) scheme. However the Essential Services Commission (**ESC**) reviewed the electricity distribution businesses' GSL payment scheme and issued the draft decision in November 2015.[141] The Victorian GSL scheme is set out in the ESC Codes – the Electricity Distribution Code and the Public Lighting Code. While the broad design of the GSL payments scheme remains unchanged, the ESC has proposed a number of changes to the scheme parameters in the draft decision to strengthen the service incentive regime. JEN submits that these changes will increase the efficient costs of providing services.

14.2 PRELIMINARY DECISION

328. This step change was not submitted in our April 2015 proposal, and therefore was not assessed in the preliminary decision. The AER's assessment framework starts with consideration of whether the proposed step changes in opex are already compensated through other elements of opex forecast, such as base year opex or the 'rate of change' component. The AER only includes a step change if it is satisfied that a prudent and efficient service provider would need an increase in its opex to reasonably reflect the opex criteria.[142]

329. One AER consideration is whether each proposed step change is driven by an external obligation (such as new legislation or regulations) or an internal management decision (such as a decision to use contractors). The preliminary decision considered that step changes should generally relate to a new obligation or some change in the service providers' operating environment beyond is control in order to be expenditure that reasonably reflects the opex criteria.[143]

14.3 JEN'S SUBMISSION

330. In its recently released draft decision, the ESC stated that the Victorian GSL payments scheme, as set out in the Codes, should continue to apply to the Victorian electricity distribution businesses during the 2016 regulatory period. However, the following changes were proposed:

- Retain all the current GSL measures as well as introduce a new GSL measure – duration of an individual interruption[144]
- Reduce the thresholds of annual frequency of unplanned sustained interruptions so that GSL payments are made to approximately 1% of the customers. All other thresholds remain unchanged[145]
- Increase the payment levels for each of the GSL measures[146]

141 ESC, *Review of the Victorian electricity distributors' guaranteed service level payment scheme, Draft decision*, November 2015.

142 AER, *Preliminary decision, Jemena distribution determination 2016-20, Attachment 7 – Operating expenditure, October 2015,* p 7-65.

143 Ibid, p 7-66.

144 ESC, *Review of the Victorian electricity distributors' guaranteed service level payment scheme, Draft decision*, November 2015, p 32.

145 Ibid, p 46.

146 Ibid, p 59.

- Align the exclusion criteria with that of the national scheme for supply interruptions due to under load shedding due to under frequency and failure of transmission connection assets. All other exclusion criteria remain unchanged.[147]

331. Each of the above requirements are further explained below.

14.3.1 GSL PAYMENT SCHEME MEASURES FOR 2016 REGULATORY PERIOD

332. As noted above, the draft decision proposed a new GSL measure – duration of interruption. Table 14–1 summarises the GSL payment scheme measures.

Table 14–1: Measures for GSL payment scheme

Measure	Change from current GSL scheme
Annual duration of unplanned interruptions	Retained
Duration of interruption	New
Annual frequency of unplanned sustained interruptions	Retained
Annual frequency of momentary interruptions	Retained
On time for appointments	Retained
New connections	Retained
Public light repair	Retained

14.3.2 GSL PAYMENT SCHEME THRESHOLD FOR 2016 REGULATORY PERIOD

333. The draft decision introduced new thresholds for the new duration of interruption measure as well as changes to the thresholds of some of the current measures. The thresholds and changes are summarised in Table 14–2.

Table 14–2: Threshold for GSL payment scheme

Measure	Current threshold	New threshold	Change
Annual duration of unplanned interruption	> 20 hour	> 20 hour	No change
	> 30 hour	> 30 hour	No change
	> 60 hour	> 60 hour	No change
Duration of interruption		CBD and urban feeders >12 hours	New threshold
		Rural feeders > 18 hours	New threshold
Annual frequency of unplanned sustained interruptions	> 10 interruptions	> 8 interruptions	More stringent threshold
	> 15 interruptions	> 12 interruptions	More stringent threshold
	> 30 interruptions	> 24 interruptions	More stringent threshold
Annual frequency of momentary	> 24 interruptions	> 24 interruptions	No change

147 ESC, *Review of the Victorian electricity distributors' guaranteed service level payment scheme, Draft decision*, 23 December 2015, p 70-71.

Measure	Current threshold	New threshold	Change
interruption	> 36 interruptions	> 36 interruptions	No change
On time for appointments	> 15 minutes late	> 15 minutes late	No change
New connections	Not connected on date agreed	Not connected on date agreed	No change
Public light repair	Within 2 business days	Within 2 business days	No change

14.3.3 PAYMENT LEVELS FOR GSL PAYMENT SCHEME FOR 2016 REGULATORY PERIOD

334. The draft decision also requires increases in payment levels as well as new payments for each measure as summarised in Table 14–3.

Table 14–3: Payment levels for GSL payment scheme

Measures	Current payment	New payment	Change
Annual duration of unplanned interruption	$100 > 20 hour	$120 > 20 hour	Increased payment
	$150 > 30 hour	$180 > 30 hour	Increased payment
	$300 > 60 hour	$360 > 60 hour	Increased payment
Duration of interruption (CBD and urban feeders)	Not Applicable	$80 >12 hours	New payment
Duration of interruption (rural feeders)	Not Applicable	$80 >12 hours	New payment
Annual frequency of unplanned sustained interruptions	$100 > 10 interruptions	$120 > 8 interruptions	Increased payment
	$150 > 15 interruptions	$180 > 12 interruptions	Increased payment
	$300 > 30 interruptions	$360 > 24 interruptions	Increased payment
Annual frequency of momentary interruption	$25 > 24 interruptions	$30 > 24 interruptions	Increased payment
	$35 > 36 interruptions	$40 > 36 interruptions	Increased payment
On time for appointments	$20	$30	Increased payment
New connections	$50 per day, $250 maximum	$70 per day, $350 maximum	Increased payment
Public light repair	$10	$25	Increased payment

14.3.4 NEW REQUREMENT TO MONITOR AND RECORD QUALITY OF SUPPLY DATA

335. In addition, the ESC is contemplating introducing quality of supply measures into the GSL payment scheme in the 2021 regulatory period. To do this effectively the ESC is proposing to require electricity distribution businesses to monitor and record quality of supply data for those customers with a smart meter in the 2016 regulatory period to collate a baseline of data to be used in setting future targets against which the future GSL will be set. The ESC stated: [148]

[148] ESC, *Review of the Victorian electricity distributors' guaranteed service level payment scheme, Draft decision*, 23 December 2015, p 30.

> *The Commission currently has no quality of supply data on which to base the introduction of a GSL payments scheme measure. However, if the Commission introduced a requirement for the electricity distributors to collect and report on the number of events experienced by each customer where the undervoltage or overvoltage limits were exceeded for more than a minute, then quality of supply measures could be introduced into the GSL payments scheme for the 2021-25 regulatory control period.*

1. In the draft decision, the ESC is proposed to amend the Electricity Distribution Code to require electricity distribution businesses to monitor and record quality of supply data for those customers with a smart meter.[149]

14.3.5 EFFICIENT COST OF COMPLYING WITH GSL SCHEME

336. As a result of the new measure, increased thresholds and payments for the GSL scheme as well as the requirement to monitor and record quality of supply data, JEN submits that the efficient cost of complying with the GSL scheme should be included in forecast opex as an opex step change.

337. To determine the increased payments expected under the proposed changes to the scheme JEN relied on GSL data prepared for the annual reporting RINs (non-financial information) over the 2011 to 2014 regulatory years and the data from our outage management system to identify the number of payments as well as the likelihood of exceeding the new threshold levels. We calculated the increase in payments for each year and averaged it over the four years. The calculation of the value of the payments and the cost build up model is provided in Attachment 8-13 of this submission.

14.3.6 EFFICIENT COST OF MONITORING, RECORDING AND REPORTING QUALITY OF SUPPLY DATA

338. To assess the increase in costs associated with the new obligation to monitor, record and report the quality of supply data, JEN considered the activities required to retrieve, analyse and report the over and under voltage events to the ESC. Power quality events caused by supply interruptions would need to be filtered out, which is time consuming. We estimate that this new obligation would require JEN to incur costs associated with an engineer for four business days per month at $183.83 per hour (4 days multiplied by 7.5 hours for 12 months).[150]

339. Table 14–4 summarises the additional costs associated with the changes to the GSL scheme including the new obligation to monitor, record and report quality of supply data.

Table 14–4: Additional costs of new GSL payment scheme and new obligation to monitor, record and report quality of supply data

ESC's GSL Review Draft Decision	Step change per annum ($, 2015)
GSL payments step change	$112,183
Quality of supply monitoring and recording	$66,179
Total	**$178,362**

340. This step change was not assessed in the preliminary decision. The AER's assessment framework starts with consideration of whether the proposed step changes in opex are already compensated through other elements of opex forecast, such as base year opex or the 'rate of change' component. The AER only includes a step

149 Ibid, p 31.

150 JEN used the labour rates for ancillary network services in the AER's *Preliminary decision, Jemena distribution determination 2016-20, Attachment 16 – Alternative control services, October 2015,* pp 16-11 to 16-13.

change if it is satisfied that a prudent and efficient service provider would need an increase in its opex to reasonably reflect the opex criteria.

341. Table 14–5 presents JEN's submission for the opex step change related to the GSL payment scheme measures for the 2016 regulatory period.

Table 14–5: GSL payment scheme step change forecast ($2015, millions)

Step change	2016	2017	2018	2019	2020	Total
GSL payment scheme	0.18	0.18	0.18	0.18	0.18	0.89

15. POWER OF CHOICE

342. 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"[151], the substantial reforms to the National Electricity Market (**NEM**) will impose an external obligation on JEN, resulting in increased opex (and capex). Therefore, including the forecast opex as a step change will allow JEN to recover its efficient costs and is consistent with the AER's approach to forecasting opex.

343. JEN did not include an opex step change for the Power of Choice (**PoC**) program in its April 2015 proposal, therefore, none was assessed in the preliminary decision.

15.1 JEN'S SUBMISSION

344. Prior to April 2015, the suite of rule changes underpinning the broader PoC program were mostly draft rule changes and therefore the scope of the change was considerably uncertain. At that time, a prudent response was to wait to see the full suite of changes and design an optimised an integrated response to minimise total compliance costs.

345. Since then, the AEMC has delivered final rule changes on a number of the PoC initiatives that provide us with sufficient certainty to include (and exclude) elements of the PoC expenditure within our submission. We have since developed a business case to ensure the coordinated program which provides a firm basis for including an estimate of the costs associated with managing and implementing the package of reforms (See Attachments 7-17 and 7-18).

346. The scale and breadth of projects under the banner of the PoC are extensive, complex and inter-related. JEN submits that a step change is necessary to enable recovery of our efficient opex costs associated with the PoC that apply during the 2016 regulatory period.

15.1.1 POWER OF CHOICE OBLIGATIONS

347. The PoC work program has, or is likely to, result in additional obligations on JEN which will require changes to our systems and processes. A summary of these obligations is outlined in Table 15–1.

Table 15–1: Summary of PoC initiatives

PoC initiative	Summary
Metering competition	On 26 November 2015, the AEMC released a new rule related to competition in metering services. The rule will facilitate a market-led approach to the deployment of advanced meters where consumers drive the uptake of technology through their choice of products and services.[152]
Customer access to data	Customers will be able to access electricity consumption data from retailers and DNSPs in an understandable format and timely manner so that they can make more informed choices about energy products and services.

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

152 AEMC, *Rule Determination, National Electricity Amendment (Expanding competition in metering and related services).*

Rule 2015, National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015, 26 November 2015.

PoC initiative	Summary
Embedded networks	This will bring increased retail competition into embedded networks by establishing a regulatory framework for embedded networks in the NER.
Shared market protocol	A set of services, service level requirements, transport and formatting rules primarily intended to facilitate service requests and responses in regard to advanced metering services.
Distribution network pricing	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.
Demand response mechanism	The demand response mechanism is a market mechanism to promote demand response from large customers.

15.1.2 FORECAST COST IMPACT OF POWER OF CHOICE PROGRAM

348. The objectives of the JEN's PoC program and solutions are to:

- Maintain comprehensive compliance of the regulatory, technical and operational environment changes set in motion by the PoC program and associated works
- Maintain continuity and availability of market system operations, so that business and market continuity is not adversely impacted through the program iterations
- Adopt the changes and ensure the market environment and solutions are efficient by continuing to support the market development activities of the PoC program through industry engagement
- Deliver an efficient cost controlled program and response to PoC changes based on a total cost of ownership perspective.

349. JEN's PoC program of work is limited to its regulated network business and does not provide for JEN to participate in a contestable metering market or any other unregulated activity. Such unregulated activity is outside of the scope of this submission.

350. Whilst the PoC program is principally capital in nature, there are once-off opex costs. In accordance with the Australian accounting standards, expenditure associated with audit, legal project initiation, program management and metering accreditation must be expensed. Consistent with our submission that capex costs associated with the PoC program be recovered (see Attachment 7-1) we also submit this step change to recover efficient opex costs. The PoC business case that presents the activities, costs and assumptions is provided as Attachment 7-17 and Attachment 7-18 of this submission.

351. Table 15–2 provides a summary of the forecast costs, the control services they relate to, and the opex category.

Table 15–2: Summary of opex associated with the Power of Choice program ($2015)

Type of cost	Metering services	Distribution services	Total
Metering opex			**$350,000**
AEMO accreditation for roles of Metering Coordinator (MC), Meter Data Provider	$350,000		

Type of cost	Metering services	Distribution services	Total
(MDP), Metering Provider (MP)			
Network opex			**$877,000**
Independent audit of PoC program		$240,000	
Legal advice on PoC Rule changes		$120,000	
Project initiation		$232,000	
IT program management and delivery support		$285,000	
Total	**$350,000**	**$877,000**	**$1,227,000**

352. Including this opex step change promotes the Optimal NEO Position because it enables JEN to recover its efficient costs associated with new obligations in providing distribution services.

353. Table 15–3 presents JEN's submission for the opex step change related to the Power of Choice program for distribution services for the 2016 regulatory period.

Table 15–3: Power of Choice step change forecast ($2015, millions)

Step change	2016	2017	2018	2019	2020	Total
Power of Choice (Distribution services)	0.39	0.49	0.00	0.00	0.00	0.88

16. ADOPTION OF CHAPTER 5A OF THE NER IN VICTORIA

16.1 JEN'S APRIL 2015 PROPOSAL

354. JEN did not propose a step change for the costs associated with Victoria's partial implementation of Chapter 5A of the NER in its April 2015 proposal. However, the Victorian Minister for Energy and Resources advised JEN in September 2015 that the Victorian Government has decided to implement Chapter 5A of the NER in Victoria within the 2016 regulatory period.

355. The Bill[153] 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 (**DEDJTR**) have advised us that the Bill will reach assent by March 2016.

356. 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.

357. The new regulatory framework for connections and the consequential changes to the Victorian regulatory instruments means JEN needs to ensure its systems, processes and websites are all updated to meet these requirements.

16.2 JEN'S SUBMISSION

358. The new regulatory framework for connections and the consequential changes to the Victorian regulatory instruments means JEN needs to ensure its systems, processes and websites are all updated to meet these requirements.

359. We are required to publish:

- A connection policy that sets out the circumstances in which retail customers and connection applicants may be required to pay connection charges to JEN
- Basic model standing offers for retailer customers who may require basic connection services with and without embedded generators
- Comprehensive connection information.

360. The policy must explain how JEN will calculate those connection charges in accordance with the connection charge principles set out in Chapter 5A and the AER's connection charge guideline. It is a substantial document to develop requiring considerable resources.

16.2.1 CONNECTION OF EMBEDDED GENERATORS UP TO 5MW

361. On 13 November 2015, the AEMC issued a final rule determination[154] to help generators less than 5MW connect to distribution networks – National Electricity Amendment (Connecting embedded generators under

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

Chapter 5A) Rule 2014, No. 8. The final determination provides for non-registered generators up to 5MW with options[155] to select the connection process under Chapter 5A.

362. Embedded generator connections are currently progressed under the ESC's Electricity Industry Guideline No. 15, which is not as prescriptive and the obligations on distribution businesses not as onerous compared to Chapter 5A of the NER.

363. The implementation of Chapter 5A means distribution businesses must respond to embedded generation connection enquires and applications under tighter timeframes[156]. Additionally distribution businesses are required to comply with the more onerous information provision requirements at the connection enquiry stage[157]. This proposed change to the Victorian connection framework means JEN will need to update and ensure its connection processes comply with the new requirements for connections of embedded generators from 30kW to 5MW.

364. In 2015, we received 67% higher embedded generator connection enquires compared to 2014 and 80% of them progressed to connection application stage. Given recent advances in battery storage technologies and changes in state and federal renewable energy policies, JEN expects that the number of connection enquiries and applications will continue to grow at a rate higher than the base opex growth.

16.2.2 ACTIVITIES TO IMPLEMENT CHAPTER 5A

365. Implementation of Chapter 5A requires JEN to:

- Develop basic connection services model standing offers for retail customers with and without embedded generators in accordance with chapter 5A[158]
- Obtain AER approval of the model standing offers[159]
- Publish comprehensive connection information including model standing basic connection offers on our website[160]
- Review and update all negotiated connection offer templates, preformatted connection contracts, and processes
- Amend the current customer capital contribution calculation model to comply with connection charge principles set out in Chapter 5A and the AER's connection charge guideline
- Update regulatory obligations in JEN's Compliance and Risk System (**JCARS**) to ensure compliance against the new connection framework.

366. The new legislation substantially changes our obligations in relation to connection, which we must implement. JEN needs to integrate the new requirements into our current business processes and monitor performance.

367. JEN considers its approach reflects the costs of a prudent operator would incur to comply with these new obligations.

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154 National Electricity Amendment (Connecting embedded generators under Chapter 5A) Rule 2014, No. 8.

155 AEMC, *National Electricity Amendment (Connecting embedded generators under Chapter 5A) Rule 2014, No. 8*, p 20.

156 NER 5A.D.2 (a), 5A.D.3 (f), 5A.F.1 (a).

157 NER 5A.D.2 (b).

158 NER 5A.B.1.

159 NER 5A.B.2.

160 NER 5A.D.1.

16.2.3 EFFICIENT COST TO IMPLEMENT CHAPTER 5A

368. JEN submits that the efficient cost of implementing Chapter 5A should be included in forecast opex through as an opex step change.

369. To determine the implementation cost, we estimated the costs based on the resources required to carry out the activities outlined in section 16.2.2. We used labour rates that the AER found to be efficient for alternative control services.[161] Whilst all of the implementation activities results in initial setup costs in 2016, some of the Chapter 5A obligations will increase costs each year.

370. Table 16–1 summarises the additional costs for the implementation of Chapter 5A for the 2016 regulatory period.

Table 16–1: Implementation costs of adopting Chapter 5A ($2015, millions)

Implementation activities	Opex step change forecast in 2016
Develop basic connection documents including application forms, model stranding offers, connection policy, and connection process for retail customers with and without embedded generators in accordance with chapter 5A (200 hrs x $94.00/hr).	0.02
Legal review of documents –for compliance with the new connection arrangements will be undertaken externally ($60k).	0.06
Restructure the webpage including publishing model standing offers, application forms, connection policy (70 hrs x $138.92/hr).	0.01
Develop customer capital contribution calculation model to comply with connection charge principles set out in Chapter 5A and the AER's connection charge guideline (70 hrs x $138.92/hr).	0.01
Update embedded generation connection processes and documents for generators from 30kW up to 5MW (160 hrs x $183.83/hr).	0.03
Update regulatory obligations in JEN's compliance and risk system (JCARS) to ensure compliance against the new connection obligations (160 hrs x $183.83/hr).	0.04
Review and update all negotiated connection offer templates, connection contracts, and processes. This is a major redevelopment of: • Connection charges policy • Negotiated connection offer • Negotiated connection contract for connection works • Negotiated connection contract supply services for large customers • Review and update tendering policies • End-to-end negotiated connection process for publication on website. Considerable effort is needed to develop the above documents (600 hrs x $94.00/hr).	0.06

161 AER, *Jemena Preliminary decision 2016-20, Attachment 16 – Alternative control services,* October 2015, p 16-11.

Implementation activities	Opex step change forecast in 2016
A part time project manager is required (0.5 FTE for 6 months) to project manage the implementation of Chapter 5A. It includes setting up of a governance and project management – including establishment of a governance committee and process to develop and manage the project plan we need regulatory reporting against the plan, regular project meetings, and end of project audit. Senior management time, technical experts are required. We have used the engineers labour rate (455 hrs x $183.83/hr)	0.08
Total	**0.30**

371. Table 16–2 summarises the ongoing costs of adopting Chapter 5A for the 2016 regulatory period.

Table 16–2: Ongoing costs of adopting Chapter 5A ($2015, millions)

Ongoing activities	Opex step change forecast per annum for 2017-20 period
Chapter 5A introduces additional obligations to progress embedded generation connection enquires and applications compared to the less prescriptive Electricity Industry Guideline No. 15. We have estimate that an additional 0.3 FTE per annum will be required to comply with the obligation to respond to preliminary inquiries and provide information. We have estimated 0.3 FTE per annum from 2017 to 2020 regulatory period.	0.10

372. The opex step change cost build-up model is in Attachment 8-13 of this submission.

373. The implementation arrangements is based on utilising a mix of existing internal and external resources across the business from regulatory, commercial, legal, new connections team, and project managers and engineers who manage negotiated connections.

374. Table 16–3 presents JEN's submission for the opex step change related to the adoption of Chapter 5A in Victoria for the 2016 regulatory period.

Table 16–3: Adoption of Chapter 5A step change forecast ($2015, millions)

Step change	2016	2017	2018	2019	2020	Total
Implementation of Chapter 5A	0.30	0.10	0.10	0.10	0.10	0.71

375. The new legislation substantially changes our obligations in relation to connection. To include the efficient costs associated with implementing the changes required promotes the Optimal NEO Position as JEN must integrate the new requirements into our current business processes and monitor performance and the opex step change should enable JEN to recover its efficient costs to comply with these new obligations.