Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review Regulatory Proposal

Revocation and substitution submission

Attachment 3-1 Incentive schemes

Public

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TABLE OF CONTENTS

List of tables

List of figures

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
capex	Capital Expenditure
CCP	Consumer Challenge Panel
CESS	Capital Expenditure Efficiency Scheme
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DMIA	Demand Management Incentive Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
EDPR	Electricity Distribution Price Review
F&A paper	AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014
GSL	Guaranteed Service Level
JEN	Jemena Electricity Networks (Vic) Ltd
MAIFI	Momentary Average Interruption Frequency Index
MED	Major Event Days
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NSP	Network Service Provider
opex	Operating Expenditure
Optimal NEO Position	The position which contributes to the achievement of the NEO to the greatest degree and best promotes the long term interests of consumers of electricity
RAB	Regulated Asset Base
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
s-factor	Service Standards Factor
STPIS	Service Target Performance Incentive Scheme
VCR	Value of Customer Reliability

OVERVIEW

Key messages

- We welcome the recognition in the preliminary decision of the importance of the incentive framework (and our response to these incentives) and in particular the preliminary decision's approach to continuing the strong and balanced incentives for delivering operating cost efficiencies and service standards through the EBSS and STPIS.
- However, we do not agree with the preliminary decision's position on exclusions under the CESS and the DMIA allowance under DMEGCIS. These positions impact the ability of JEN to recover at least its efficient costs and have the potential to impact efficient investment in our distribution system, efficient provision of electricity network services and the efficient use of the distribution system. This is not consistent with the aims of section 7A of the National Electricity Law (**NEL**) and does not promote the **Optimal NEO Position**.[1]
- Jemena Electricity Networks (Vic) Ltd (**JEN**) maintains its position from the April 2015 proposal in relation to excluding reliability improvement capital expenditure (**capex**) from the CESS incentive and the proposed demand management incentive allowance (**DMIA**) amount as this will:
  - Deliver and drive efficient investment in, and operation of, JEN's electricity system and promote the Optimal NEO Position:
  - Ensure the efficiency principles of the STPIS operate as intended, consistently, and in co-ordination with, the other incentive schemes;
  - Support innovation investment and improve network capability to optimally interface with emerging technologies and demand management proponents to deliver benefits to consumers over the long term.
- In order to ensure the incentive schemes operate to deliver benefits to consumers, encourage efficient investment in, and efficient operation and use of electricity services and promote the Optimal NEO Position it is necessary to ensure that the incentive schemes are co-ordinated (rather than in conflict) and that the allowed operating expenditure (**opex**) and capex is sufficient to cover at least JEN's efficient costs. JEN's submission addresses the appropriate allowance for capex and opex in Attachments 7-1 and 8-1 respectively. JEN considers that the adjustments to the incentive schemes set out in this attachment are necessary to ensure the incentive schemes deliver the intended benefits and promote the Optimal NEO Position.

1. The April 2015 proposal (together with any supporting material contained or referred to in the April 2015 proposal) is incorporated into, and forms part of this submission.
2. The table below summarises our response to the preliminary decision.

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

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

Form of regulation and risk management frameworks	Our response to preliminary decision
Efficiency benefit sharing scheme (**EBSS**)	✓
Capital expenditure efficiency scheme (**CESS**)	✗
Service target performance incentive scheme (**STPIS**)	✓
Demand management and embedded generation connection incentive scheme (**DMEGCIS**)	✗
F-factor scheme	✓

1. INTRODUCTION

1.1 INCENTIVE SCHEMES AND THE NEO

3. Appropriate incentive schemes, (coupled with recovery of at least the efficient costs incurred by a Distribution Network Service Provider (**DNSP**), can promote the Optimal NEO Position by encouraging DNSPs to continuously improve their provision of electricity services via a system of rewards and penalties which are shared between the DNSPs and their consumers.

4. The NEL attempts to achieve the NEO by seeking to strike a balance between enabling a DNSP to recover at least its efficient costs of providing electricity services, complying with regulatory requirements[2] and providing effective incentives to promote economic efficiency with respect to the standard control services. The economic efficiency that the NEL seeks to promote includes:

   - Efficient investment in a distribution system or transmission system with which the operator provides direct control network services
   - The efficient provision of electricity network services
   - The efficient use of the distribution system or transmission system with which the operator provides direct control network services.[3]

5. The incentive framework set out in the National Electricity Rules (**NER**) includes a number of incentive schemes to encourage continued improvements in the services DNSPs provide, including improvements in cost efficiency, service standards and management of network demand. These include the EBSS[4], the CESS[5], the STPIS[6], the demand management and DMEGCIS[7] and the small-scale incentive scheme[8].

6. The effectiveness of these incentive schemes depends upon a number of factors including:

   - How the schemes are defined and, in particular, whether any factors which may artificially distort results are included or excluded from consideration
   - How the various schemes interrelate and co-ordinate with each other. In order for the incentive schemes to work efficiently and as an integrated whole (so that they drive the appropriate behaviour and achieve their aims) the schemes need to operate in a consistent and co-ordinated manner. If the schemes are in conflict (ie one scheme rewarding certain behaviour whilst another scheme penalises the same conduct) then they are likely to distort investment and operational decisions and will not promote the Optimal NEO Position

[2] NEL section 7A(2)
[3] NEL cl 7A (3)
[4] NER cl 6.5.8(a)
[5] NER cl 6.5.8A
[6] NER cl 6.6.2(a)
[7] NER cl 6.6.3(a)
[8] NER cl 6.6.4(a)

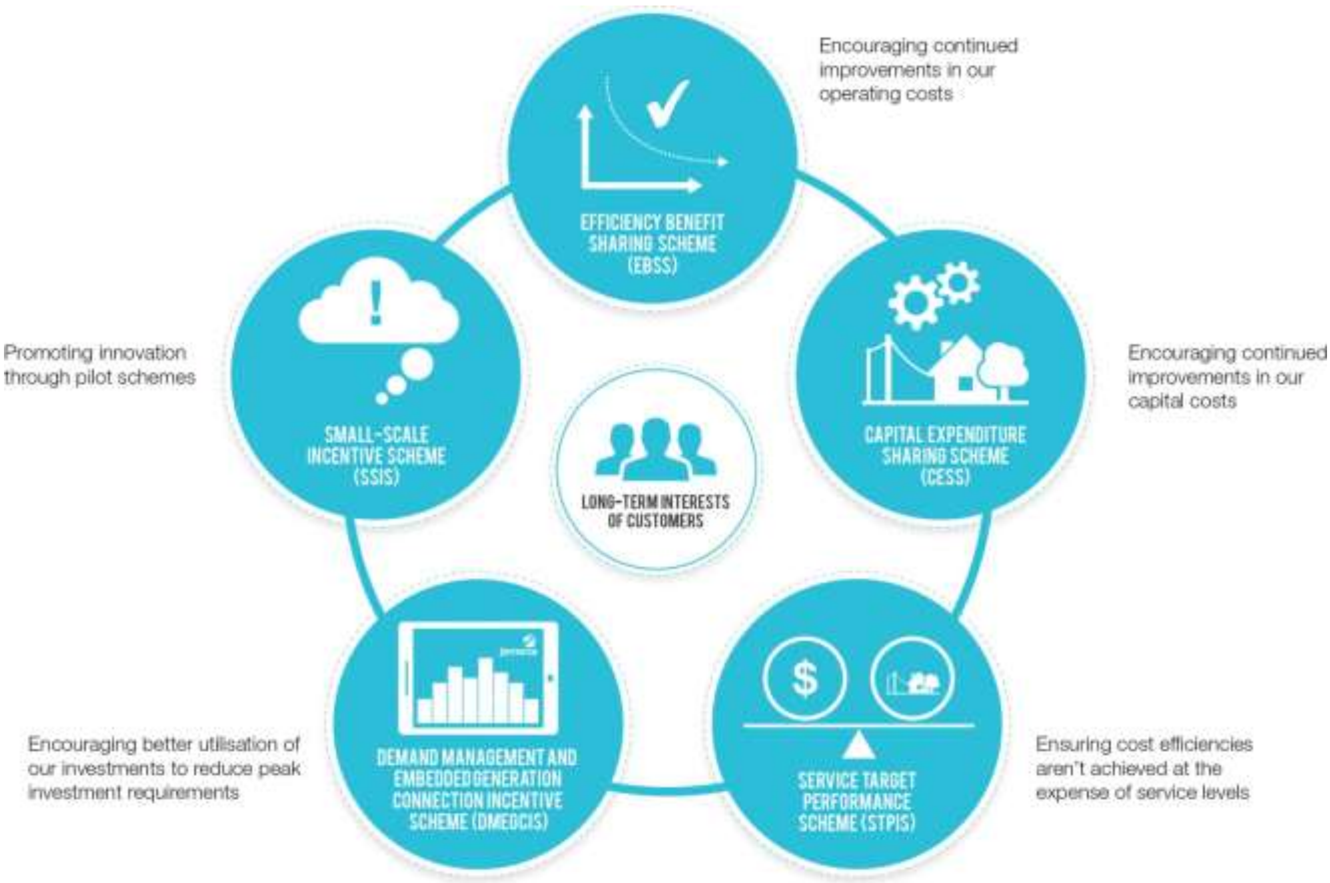
- How the schemes interrelate with the opex and capex levels allowed to the DNSP. For example, if the allowed opex or capex is insufficient to cover at least the efficient costs of the DNSP then the DNSP may not have sufficient funds to deliver a reliable service. Imposing penalties for providing the level of service required in such circumstances could impact the level of investment that a DNSP could attract. An impact on investment could in turn further impact price, quality, reliability and security of supply of electricity. This will not promote an Optimal NEO Position.

In order to promote the Optimal NEO Position it is necessary to provide an effective, efficient and co-ordinated balance between the various incentive schemes and between those schemes and the revenue allowed to the DNSPs.

1.2 APPLICABLE INCENTIVE SCHEMES FOR THE 2016 REGULATORY PERIOD

7. The Australian Energy Regulator (**AER**) is required[9] to publish its proposed approach to incentive schemes in its framework and approach paper (**F&A paper**).[10]

Figure 1–1: Incentive schemes in the NER are designed to improve long-term outcomes for our consumers



9 NER cl 6.8.1(b)(2)

10 AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014

8. The NER[11] require us to indicate how these incentive schemes should apply to our services for the 2016 regulatory period, taking account of how the AER intends to apply these schemes as set out in its F&A paper (see Attachment 5-3 of our April 2015 proposal).

9. In our April 2015 Proposal we set out our positions on the application of the EBSS, CESS, STPIS, DMEGCIS, small scale incentive scheme and the closure of the retired s-factor scheme. This submission maintains and builds upon JEN's April 2015 Proposal.

10. In addition, the Victorian Government prescribes an f-factor scheme under an Order issued under the *National Electricity (Victoria) Act 2005*. The objective of the f-factor scheme is to provide incentives for Victorian DNSPs to:

- Reduce the risk of fire starts due to electricity infrastructure
- Reduce the risk of loss or damage caused by fire starts.

11. In the following sections of this attachment JEN provides our response to the preliminary decision on the; EBSS, CESS, STPIS, DMEGCIS incentive schemes, the f-factor and the closure of the retired s-factor scheme. JEN does not seek the application of a small scale incentive scheme.

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

[11] NER cl S6.1.3

2. EFFICIENCY BENEFIT SHARING SCHEME

13. In most markets, businesses are driven to continually seek to improve their cost efficiency driven by customer expectations, competitors or shareholders. However, it is perceived that regulated network businesses can have less incentive to seek such improvements because the five year price reset process creates an artificial break in the incentives they face.[12]

14. The EBSS is designed to overcome this perception by providing a continuous incentive for DNSPs to achieve efficiency savings over time and improve the value for money of our services by sharing these savings with our consumers.[13] Under this scheme, savings from efficiency gains over a regulatory period (or penalties for efficiency losses over this period) are added to (or subtracted from) our annual revenue requirements for the next regulatory period. The EBSS applied for the 2011 regulatory period.

15. To work effectively, the EBSS scheme allows a number of exclusions from the efficiency assessment.

16. Table 2–1 provides a summary of JEN's April 2015 proposal, the preliminary decision and JEN's submission.

Table 2–1: Summary of proposed exclusions and preliminary decision

Proposed exclusions from the EBSS	JEN April 2015 proposal - reasons	Preliminary decision	JEN's response	JEN's submission
Debt raising	Not forecast using a single year revealed cost approach	Excluded from EBSS – not covered by revealed cost opex allowance	✓	Same as April 2015 proposal
Non-network	Not forecast using a single year revealed cost approach	Not excluded – covered by revealed cost opex allowance and sufficiently incentivised by the CESS	✓	No exclusion - CESS and EBSS provides sufficient incentive to seek non-network alternatives if they are lower total expenditure (opex and capex)
Self-insurance	Not forecast using a single year revealed cost approach	Not excluded – covered by revealed cost opex allowance	✓	No exclusion - accept in base year
DMIA	Not forecast using a single year revealed cost approach	Excluded from EBSS – not covered by revealed cost opex allowance	✓	Same as April 2015 proposal
Guaranteed service level (**GSL**)	Not forecast using a single year revealed cost approach, and subject to jurisdictional GSL scheme	Excluded from EBSS – not covered by revealed cost opex allowance	✓	Same as April 2015 proposal
EDPR costs	Not forecast using a single year revealed cost	Not excluded – covered by revealed cost opex	✓	No exclusion – accept in base year

12 If a DNSP make savings late in the regulatory period they will be immediately taken out of allowed prices as part of the five year price reset. This is perceived to dampen a DNSPs incentive to make efficiency savings, and is unlikely to be in the long-term interest of consumers.

13 Operating efficiency gains or losses are shared approximately 30:70 between distributors and consumers. AER, *Final Framework and Approach for the Victorian Electricity Distributors*, October 2014, p105.

Proposed exclusions from the EBSS	JEN April 2015 proposal - reasons	Preliminary decision	JEN's response	JEN's submission
	approach			
Losses on the scrapping of assets	Losses on the scrapping of assets relates to capital items brought to account, their inclusion in the operating expenditure EBSS scheme would distort scheme operation	Excluded from EBSS – does not reflect actual opex outlaid	✓	Same as April 2015 proposal
Defined benefit superannuation provisions	Does not accurately reflect the costs faced by JEN and is a cost that JEN does not control	Not excluded – covered by revealed cost opex allowance	✓	No exclusion - accept in base year
Pass through events	Is a cost that JEN does not control which if included is not consistent with providing a continuous incentive to reduce opex	Excluded from EBSS – where made after the initial regulatory decision	✓	Same as April 2015 proposal

2.1 JEN'S APRIL 2015 PROPOSAL

17. JEN outlined in Chapter 5 of its April 2015 Proposal how we consider the EBSS should be applied for the 2016 regulatory period and provided further supporting information in Chapter 4 of Attachment 5-3: Application of Incentive.

2.1.1 APPLICATION OF EBSS OVER THE 2016 REGULATORY PERIOD

18. We generally support the application of the EBSS set out in the preliminary decision over the 2016 regulatory period. However, in the April 2015 proposal JEN identified the following costs which JEN considered should be excluded from the calculations of efficiency gains or losses to ensure that our performance against the opex benchmarks is not distorted and is consistent with the original intent of the EBSS:

- Consistent with clause 2.1.1 of the EBSS,[14] costs which are not forecast using a single year revealed cost approach but are instead specific forecast costs are excluded from the operation of the EBSS. For example:
  - Debt raising costs
  - Non-network alternative costs—to account for the impact of, for example, demand management alternatives converting forecast capex spend into actual opex spend
  - Self-insurance
  - DMEGCIS costs—these costs are subject to the DMEGCIS and should not be included in two schemes

14 AER, *Better Regulation, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013

  - GSL payments—these are subject to a separate jurisdictional GSL scheme and should not be included in two schemes
  - Electricity Distribution Price Review (**EDPR**) costs—costs incurred for preparing the EDPR proposal
  - Losses on the scrapping of assets.
- Costs beyond our reasonable control such as:
  - The impact of superannuation defined benefits schemes—these reflect changes in provisions resulting from application of Australian Accounting Standards
  - The impact of any pass-throughs.

2.1.2 OUTCOMES OVER THE 2011 REGULATORY PERIOD

19. JEN proposed that $23m be added to its revenue for the 2016 regulatory period for the carryover of amounts accrued under the EBSS during the 2011 regulatory period.

20. JEN adjusted its approved opex forecast to account for the difference between forecast growth and actual network growth. JEN also excluded debt raising costs, self-insurance, the DMIA and GSL payments.

2.1.3 INTERRELATIONSHIPS WITH OTHER PARTS OF OUR REGULATORY PROPOSAL

21. When the EBSS, CESS and STPIS apply to JEN, and these schemes are appropriately defined and calculated, incentives for opex, capex and service are balanced. The schemes provide us with an incentive to pursue efficiency improvements in opex and capex, and to share them with our consumers.

22. Incentives for opex and capex are balanced (at approximately 30%) under the implied fair sharing ratios. The incentives are also balanced in that the STPIS encourages us to make targeted efficient decisions on when and what type of expenditure to incur, in order to meet our service reliability targets.

23. The preliminary decision adopts a revealed cost approach to setting the efficient base year opex.

2.2 PRELIMINARY DECISION

24. The preliminary decision recognises incentives for service providers to pursue efficiency improvements in opex by allowing service providers to keep any difference between its approved forecast and its actual opex during a regulatory control period. The EBSS provides an additional reward for reductions in opex and penalties for sustained increases in opex. The scheme works to provide a continuous incentive for a service provider to pursue efficiency gains over the whole of the regulatory control period.

2.2.1 EBSS TO APPLY FOR THE 2016 REGULATORY PERIOD

25. The preliminary decision has confirmed that the EBSS to apply for the 2016 regulatory period is the approach outlined in its Better Regulation Program and proposed by JEN. The preliminary decision accepted JEN's proposal to exclude debt-raising costs, DMIA and GSL payments because these forecasts are not based on revealed expenditure but rather are determined as category specific forecasts. The preliminary decision also accepted JEN's proposal to exclude losses from the scrapping of assets because these costs reflect an accounting adjustment rather than an actual cash outlay made by a service provider in providing network services. If it is included in the calculation of EBSS, JEN will be penalised or rewarded for accounting adjustments. The preliminary decision also indicated that it would adjust forecast opex to add or subtract any approved revenue increments made after the preliminary decision which may include pass through amounts.

26. The preliminary decision did not accept that opex associated with non-network alternatives, self-insurance, EDPR costs or superannuation for defined benefits and retirement schemes be excluded from the EBSS. The preliminary decision considered that these costs are included in the base year opex and expects to use the same method in the next regulatory period. The preliminary decision has excluded non-network alternatives in past regulatory periods because of the imbalance between opex and capex incentive schemes. However, the preliminary decision considered that the introduction of the CESS including non-network alternative costs, meant that the EBSS maintains the balanced incentive for JEN to consider demand management and other forms of non-network alternative expenditure as an efficient substitute to network solutions.

27. In addition, the preliminary decision foreshadowed that in addition to the excluded cost categories, it would also:

- Adjust forecast opex to add any approved revenue increments made after the preliminary decision
- Adjust actual opex to add capitalised opex that has been excluded from the Regulated Asset Base (**RAB**)
- Excluded categories of opex not forecast using a single year revealed cost approach for the regulatory control period beginning in 2021 where doing so better achieves the requirements of the clause 6.5.8.

2.2.2 EBSS CARRYOVER FROM THE 2011 REGULATORY PERIOD

28. The preliminary decision approved an EBSS carryover amount of $24.9m from the application of the EBSS during the 2011 regulatory period. The difference between the preliminary decision's calculation and JEN's April 2015 proposal is:

- Adjustments made to account for new regulatory information notices compliance costs which increased the carryover amount
- Exclusion of movements in provisions which decreased the carryover amount.

29. The preliminary decision excluded RIN compliance costs because these resulted from a new or changed regulatory obligation. The preliminary decision adjusted movements in provisions because the AER considered that these movements should not be treated as actual opex for the purpose of measuring efficiency gains or losses.

2.3 JEN'S RESPONSE AND THIS SUBMISSION

30. We accept the preliminary decision's position on the EBSS carryover amount to be added to the revenue requirement for the 2016 regulatory period from the 2011 regulatory period, which is higher ($24.9m) than the amount JEN proposed in its April 2015 proposal ($23m) as a result of removing RIN compliance costs and provisions from reported opex.

31. We have incorporated the preliminary decision on the 2011 EBSS carryover amount into our submission on the basis that:

- RIN compliance costs reflect new regulatory requirements and it is consistent with the operation of the scheme for these to be excluded, and
- Provisions reflect an accounting adjustment rather than an actual outlay made by a service provider in providing network services.

32. We also note the preliminary decision's position on how the EBSS will apply in the 2016 regulatory period and the decision not to exclude non-network alternatives, self-insurance, EDPR costs and superannuation for defined benefits and retirement schemes.

33. We welcome the preliminary decision's endorsement and acceptance of JEN's proposal to exclude:[15]

- Costs associated with debt raising, DMIA, GSL payments as these forecasts are not based on revealed expenditure
- The losses on scrapping of assets as this forecast reflects an accounting adjustment
- Any pass through costs on the basis that these amounts represent costs beyond JEN's reasonable control.

34. The exclusion of these items ensures that the EBSS incentive scheme avoids distortions to the calculation of incentive amounts and thus ensures that the EBSS incentive scheme can operate to encourage efficiency gains in a way which promotes the Optimal NEO Position.

35. JEN notes that the preliminary decision has allocated some costs from alternative control services (metering services) to distribution services (standard control services). JEN has not incorporated this element of the preliminary decision into its submission. However, to the extent that the substitute decision results in a different allocation of costs between distribution services and alternative control services, the EBSS should be implemented based on the allocation adopted in the preliminary decision to ensure that JEN is not penalised under the EBSS because of costs incurred in providing alternative control services. This is outlined further in Attachment 6-1 of this submission.

36. We agree with the position in preliminary decision that the CESS will reduce the negative impact on the incentives to undertake non-network alternatives that would exist if these costs are not excluded from the calculation of carryover amounts for the EBSS in the absence of a CESS. JEN notes that the effective balance between the incentives under the CESS and EBSS will be reviewed at the conclusion of the 2016 regulatory period and this experience may inform the future treatment of cost categories to be excluded from the scheme.

We have incorporated the position from the preliminary decision to not exclude self-insurance, EDPR costs and superannuation for defined benefits and retirement schemes on the basis that these will be included in the single base year revealed cost approach to forecasting opex for the 2016 regulatory period. Should this not be the case in the substitute determination, JEN maintains the position set out in its April 2015 Proposal.

2.4 INTERRELATIONSHIPS

37. The preliminary decision has allowed forecast opex for the EBSS as outlined in Table 2–2.

Table 2–2: Preliminary decision on JEN's forecast opex for the EBSS ($ million, 2015)

	2016	2017	2018	2019	2020
Forecast opex for the EBSS	75.8	76.0	77.0	78.2	79.5

Source: AER, *Preliminary Decision Jemena distribution determination 2016 to 2020, Attachment 9 – Efficiency benefit sharing scheme, October 2015*, Table 9.2, p 9-7

38. We have responded to the position from preliminary decision on forecast opex in Attachment 8-1 of this submission.

39. In order for the EBSS to operate to achieve the aims of the scheme it must:

- Be balanced and co-ordinated with the other incentive schemes; and

[15] AER, *Preliminary Decision Jemena distribution determination 2016 to 2020, Attachment 9 – Efficiency benefit sharing scheme, October 2015*, pp, p 9-11 to 9-12.

- Operate in circumstances where JEN's approved level of opex enables JEN to recover at least its efficient costs of providing electricity services, complying with regulatory obligations or making a regulatory payment.

40. We discuss the possible issues that may arise in co-ordinating the EBSS with the CESS and STPIS in sections 3.4.

41. As indicated in Attachment 8-1, JEN does not consider that the preliminary decision has set opex at a level that enables JEN to recover at least its efficient costs. Given this, it is likely that the EBSS incentive scheme will not work effectively to drive efficiency gains and may instead dis-incentivise investment in the electricity system, which may, in turn, impact the price, quality, reliability and security of supply of electricity. This would not lead to an Optimal NEO Position.

42. In order for the EBSS scheme to operate as designed JEN considers that the opex requirements set out in JEN's submission should be accepted.

3. CAPITAL EXPENDITURE SHARING SCHEME

43. The CESS is designed to reward network businesses when they improve the efficiency of their capital expenditure, and penalise them when the efficiency of this expenditure diminishes. Under the scheme, financial rewards from capital efficiency gains—or financial penalties for capital efficiency losses—over a regulatory period are added to (or subtracted from) the business' annual revenue requirements for the next regulatory period.[16] The CESS is a new incentive scheme, developed in response to the Australian Energy Market Commission (**AEMC**) changes to the NER,[17] to enhance the financial incentives for network businesses to improve their capital expenditure efficiency.

44. In devising the CESS the NER requires the AER to take into account:

- The capital expenditure sharing scheme principles, namely:
  - That DNSPs should be rewarded for improvements or penalised for declines in efficiency of capital expenditure
  - The rewards and penalties should be commensurate with the efficiencies or inefficiencies in capital expenditure[18]
- The interaction of the scheme with other incentives a DNSP may have in relation to efficient operating to capital expenditure[19]
- The capital expenditure objectives, and, if relevant, the operating expenditure objectives[20]
- The circumstances of the DNSP.[21]

45. In its April 2015 proposal JEN proposed a CESS which largely accorded with the AER's Capital Expenditure Incentive Guideline with two exceptions:

- JEN proposed a number of exclusions from the CESS Scheme
- JEN proposed an alternative method of applying the CESS Scheme in the 2021 regulatory period.

46. JEN also proposed that any CESS amounts included in our regulated revenue requirements in the 2021 regulatory period be amortised over that regulatory period to avoid asymmetry in time horizons of benefits and penalties between the EBSS and the CESS and to smooth the effect of any adjustments.

47. Table 3–1 provides a summary of JEN's submission on exclusions from the CESS scheme.

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16 These rewards or penalties are added or subtracted as a separate building block in calculating the annual revenue requirements.

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

18 NER cl. 6.5.8A(c)

19 NER cl. 6.5.8A(d)(1)

20 NER cl. 6.5.8A(d)(2)

21 NER cl. 6.5.8A(e)(4)(ii)

Table 3–1: Summary of JEN's submission on exclusions from the CESS scheme

Proposed exclusions from the scheme	JEN April 2015 proposal - reasons	Preliminary decision	JEN's response	JEN's submission
Reliability improvement capex	Reduces the incentive for service improvements	Do not exclude as CESS, EBSS and STPIS remain balanced	✗	Same as April 2015 proposal
Cost pass through capex	Not inefficient to increase capex if required	Exclude – allowance increased where approved pass through event as per the Capital Expenditure Incentive Guideline	✓	Same as April 2015 proposal
CESS amounts be amortised over 2021 regulatory period	Avoid asymmetry and smooth adjustments	Do not accept JEN's proposal for amortisation	✓	Accept preliminary decision

3.1 JEN'S APRIL 2015 PROPOSAL

48. The preliminary decision confirmed that the CESS would apply for the 2016 regulatory period as outlined in the F&A paper, and outlined how the scheme would be implemented as part of its Better Regulation program.[22]

49. JEN proposed that the CESS apply to JEN broadly in line with the approach outlined in the F & A paper, with only minor modifications to exclude reliability improvement capex and capex approved as a part of a pass-through application.

50. To calculate the rewards or penalties, the CESS scheme accounts for adjustments for any excluded costs. To ensure our performance against the capex benchmarks and other incentive schemes is not distorted, we proposed that reliability improvement capex be excluded from the CESS, for the reasons in our submission to the Better Regulation consultation.[23] We also proposed that CESS rewards and penalties be amortised over the regulatory control period.

51. In its submission to the Better Regulation consultation, JEN indicated that principles for exclusion should be that:

- The expenditure is outside the DNSP's control e.g. growth or connections-related expenditure where there is a universal connection obligation, or
- Failure to exclude the costs would distort the intended incentive properties of other parts of the regulatory regime applied to that DNSP.

52. An example of costs in the latter category is expenditure on reliability and quality improvements capex made in response to the incentives provided by the STPIS. That expenditure is not forecast on an ex ante basis and so could contribute to total capex exceeding the allowance if not excluded. Given that it is justified on the basis of the STPIS criteria and intended incentive rate, the expenditure should be excluded when determining whether

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

[23] The service target performance incentive scheme (**STPIS**) provides financial incentives for us to incur prudent capex that improves levels of service performance. This capex is not forecast on an ex ante basis and so could contribute to our actual capex exceeding the benchmark allowance, if not excluded. In turn, this would overstate penalties for capex overspends, and understate rewards for capex underspends. Jemena, *Submission to AER issues Paper: Expenditure incentives guidelines for electricity network service providers*, May 2013.

an ex post review is required and that exclusion step should be included in the staged assessment approach. The expenditure should also be excluded in applying any CESS. If reliability improvement expenditure is not excluded, then the penalties for over-expenditure would be over-stated and rewards for under-expenditure would be under-stated, effectively eroding and distorting the STPIS incentives.

53. JEN proposed that the rewards and penalties under the CESS be amortised over the period to reduce the difference between tariff revenue and building block revenue at the end of the regulatory period. That is, the rewards and penalties would be deemed to apply in each year rather than a one-off adjustment in the first year.

3.2 PRELIMINARY DECISION

54. The preliminary decision did not accept the modifications to the CESS scheme proposed by JEN to:

- Exclude reliability improvement capex from the CESS to ensure that the incentives are not distorted by providing greater penalties for capex overspending and providing lower rewards for capital expenditure underspending; and
- Amortisation of rewards and penalties over the 2016 regulatory period.

3.2.1 RELIABILITY IMPROVEMENT CAPEX

55. The preliminary decision did not support JEN's proposal to exclude reliability improvement capex because the AER considered that such an approach may distort expenditure towards reliability capex that is not valued by consumers. In support of this position the preliminary decision also referred to the reasons outlined in the AER's explanatory statement for the capital expenditure incentive guideline[24] which included the following:

- It is unclear whether applying a different sharing ratio for investments in reliability would lead to better outcomes for consumers
- Excluding reliability capex from the CESS does not mean that a distributor's incentive to achieve efficiencies in capex will be balanced with its incentives to invest in reliability
- If reliability capex is not included in the CESS it will mean that distributors face a sharply declining penalty for undertaking reliability capex within a regulatory control period. As there is only a small penalty for a distributor who undertakes capex at the end of the regulatory control period, distributors would be strongly incentivised to undertake reliability improving investments towards the end of a period rather than at the start. This may lead to reliability capex that is not valued by consumers
- It would be difficult to identify and verify discrete reliability capex projects for exclusion.

3.2.2 AMORTISATION

56. The preliminary decision did not accept JEN's proposal to amortise rewards and penalties on the basis that the AER considered JEN did not provide supporting reasons or specify how it would differ from the current mechanism which treats CESS as a separate building block which is then smoothed throughout the next period. Further, the preliminary decision stated JEN did not detail why its proposal would be preferable to the approach in the guideline.

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

3.3 JEN'S RESPONSE AND THIS SUBMISSION

3.3.1 RELIABILITY IMPROVEMENT CAPEX

57. We do not agree with the preliminary decision not to exclude reliability improvement capital expenditure from the operation of the CESS for the following reasons:

- The aims of the NER and NEL are to achieve the NEO by promoting efficient investment in, and efficient operation and use of the DNSP's electricity systems[25]
- One mechanism included in the NER to promote the NEO is the use of incentive schemes such as the CESS, STPIS and EBSS. In order to promote the Optimal NEO Position and achieve the objectives behind the schemes they need to operate in a clear, consistent and co-ordinated manner so that:
  - Efficient expenditure is encouraged (not discouraged), ie. DNSPs are rewarded for improvements in efficiency of capex and penalised for declines in efficiency of capex[26]
  - Behaviour which could result in a decline in service standards is not incentivised, ie. the capex objectives of maintaining quality, reliability, security and safety of the distribution system are promoted[27]
  - DNSPs are able to plan their activities with certainty as to the outcome of their investment and operational decisions, ie. the capital expenditure incentive objective and the capital expenditure criteria[28] are promoted and rewards and penalties are commensurate with the efficiencies or inefficiencies in capital expenditure[29]
  - The incentive schemes interact in a manner which promotes efficient operating or capital expenditure[30]
  - The schemes are tailored to take into account the capital expenditure sharing scheme principles as they apply to each DNSP and the circumstances of those DNSPs[31]
  - The schemes err on the side of incentivising additional investment as it has been recognised (including by the former AER Chairman Andrew Reeves) that the economic cost of under-investment is greater than the economic cost of over-investment[32]
- By not excluding the reliability improvement capex from the CESS the preliminary decision does not provide incentive schemes that are clear, consistent and co-ordinated in the manner set out above. Thus the schemes do not address the NEL and NER requirements, may not create an effective and efficient incentive scheme in the long term interests of consumers and would not promote the Optimal NEO Position.
- To illustrate this:
  - The preliminary decision has adopted the value of customer reliability (**VCR**) to measure rewards and penalties under the STPIS and ensure that the DNSP's operational and investment strategies are consistent with the value consumers place on the reliability of electricity services

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[25] NEL, section 7

[26] NER cl. 6.5.8A(c)(1)

[27] NER cl. 6.5.7(a)

[28] NER cl. 6.4A(a) and cl 6.5.7(c)

[29] NER cl. 6.5.8A(c)(2)

[30] NER cl. 6.5.8A(d)(1)

[31] NER cl. 6.5.8A(e)(4)

[32] See AER Chairman's address (published transcript), AEMC public forum, 23 November 2011 "*…it is recognised that the economic cost of under-investment in services is greater than the economic cost of a small over-investment. This asymmetry is well understood in regulatory economics and is key to the deliberations of regulators….*"

- If consumers are willing to pay for improvements those improvements should be made where they are consistent with the long term interests of consumers. If the improvements are not made the DNSPs risk being penalised under the STPIS. The STPIS therefore provides a clear incentive for DNSPs to undertake the improvements
- If, by contrast, the calculation of the CESS was to include the costs of such improvements then undertaking those improvements may result in the DNSP being penalised under the CESS
- The incentive schemes would then be in conflict, driving the opposite behaviour, and requiring the DNSP to make a choice as to the 'least worst' outcome. As each option could involve a penalty (ie not undertaking improvements could lead to a STPIS penalty but undertaking the improvements could lead to a CESS penalty) this would be an undesirable outcome, which could affect the likely returns of the DNSPs and thus their attractiveness for investment. Any impact on investment could in turn impact the price, quality, safety, reliability and security of the supply of electricity services. It would also undermine the ability of the incentive schemes to encourage efficient expenditure and create the perverse result of applying penalties for service improvements. The preliminary decision would thus not have appropriately considered the interaction of the CESS with the other incentive schemes
- The CESS would not be rewarding improvements in efficiency of expenditure of capex if any such reward was offset by a STPIS penalty
- The CESS could incentive declines in service standards if the DNSPs had to abandon reliability improvements to avoid CESS penalties.

58. Further, JEN reiterates that excluding reliability improvement capex is consistent with achieving the objectives of the CESS. The preliminary decision acknowledges that the CESS is designed to penalise JEN for efficiency losses and provide rewards for efficiency gains. Where JEN assesses that a reliability improvement project would be efficient under the STPIS (because it costs less to deliver the benefits to consumers than the consumers values those benefits), the CESS should not penalise JEN. Under the package of incentives outlined in the preliminary decision, JEN would be penalised under the CESS for making this reliability improvement capex (because capex would be greater than forecast) which would reduce the reward JEN would receive under the STPIS, and efficient outcomes for consumers. Such an outcome cannot promote the Optimal NEO Position**.**

59. The NER requires that the AER must take into account any other incentives when developing and implementing a STPIS[33]. Under the preliminary decision, the AER has not taken into account the impact on the STPIS of the CESS. The result is a lower reward under the STPIS (or a higher threshold for undertaking the expenditure) than is consistent with the value of the reliability improvement to consumers. This is an inefficient outcome – and does not achieve the Optimal NEO Position.

60. JEN also considers the reasons the preliminary decision has provided for rejecting JEN's proposal are not justified and do not outweigh the detriments which arise from a failure to exclude reliability improvement capex from the CESS. In particular:

- The preliminary decision contends that excluding reliability improvement capex from the CESS may distort expenditure towards reliability expenditure which is not valued by customers. JEN considers that this is unlikely to occur as such expenditure would not support the long term interests of consumers and may not meet the capex criteria and thus a DNSP who undertook such expenditure would be at risk of having the expenditure excluded from the DNSP's RAB on an ex-post review. Thus the measures the AER has in place to review capex spend—together with the principles in the NER—are sufficient to ensure this does not occur. We consider this position also ignores the particular circumstances of JEN, namely that JEN has been found to be operating efficiently and to be engaging in a meaningful and genuine way with our consumers

[33] NER cl 6.6.2(b)(3)(iv)

- The preliminary decision contends that it would be difficult to identify and verify discrete reliability capex projects for exclusion. JEN does not agree that this would be the case. The RINs (benchmarking/category analysis) captures reliability improvement capex and therefore, it could be utilised to capture discrete reliability improvement capex. In addition, if the AER had concerns about any reliability capex spend it would have the ability to undertake an assessment in an ex-post review of capex. JEN indicated in its April 2015 proposal that we advocate a full and transparent consultation in all stages of any such ex-post review. Such a review could identify and verify reliability capex projects for exclusion
- The preliminary decision states that excluding reliability capex from the CESS does not mean that a distributor’s incentives to achieve efficiencies in capex will be balanced with its incentives to invest in reliability. However, it does not mean that they will not be balanced and this argument also ignores the very real disincentives to invest in reliability which could arise if the CESS does not exclude reliability capex
- The preliminary decision states that it is unclear whether applying a different sharing ratio for investments in reliability would lead to better outcomes for consumers. However, any such “uncertainty” is not a compelling reason for refusing to exclude reliability capex given the obvious detriments of failing to do so.

61. The Optimal NEO Position is promoted where the financial incentive provided to distributors for service performance reflects the VCR. It is an error to conclude that the financial incentive for service performance be set to the VCR and then not make the necessary adjustment to the CESS to exclude reliability improvement performance. It is also an error not to ensure that the CESS and the STPIS operate in a co-ordinated manner so as to incentivise efficient expenditure and the maintenance and improvement of service performance.

3.3.2 AMORTISATION

62. We accept the position from the preliminary decision on the amortisation and have incorporated it into this submission on the basis that the impact on the ability to align the tariff revenue with the building block revenue in the final year is not material.

3.4 INTERRELATIONSHIPS

63. There are interrelationships between the CESS and the approved level of capex and between the CESS and other incentive schemes such as STPIS and EBSS.

64. In order for the CESS to operate to achieve the aims of the scheme it must:

- Be balanced and co-ordinated with the other incentive schemes
- Operate in circumstances where JEN’s approved level of capex enables JEN to recover at least its efficient costs of providing electricity services, complying with regulatory obligations or making a regulatory payment.

65. As indicated in Attachment 7-1, JEN does not consider that the preliminary decision has set capex at a level which enables JEN to recover at least JEN’s efficient costs. Given this, it is likely that the CESS incentive scheme will not work effectively to ensure efficiency of expenditure and may instead operate to negatively impact investment in the electricity system which may in turn impact the price, quality, reliability and security of supply of electricity services. This would not lead to an Optimal NEO Position.

66. In order for the CESS to operate as designed JEN considers that the capex requirements set out in JEN’s submission should be accepted. This would enable JEN to recover at least JEN’s efficient costs so that the CESS can operate as intended, namely, as an incentive to drive efficiency in expenditure rather operating as a disincentive to efficient investment in JEN’s network with the attendant impacts on price, quality, reliability and safety of the electricity network.

67. The interrelationships between the CESS and the STPIS are discussed above.

68. In addition the CESS interrelates with the EBSS in a number of ways. If the level of opex is not sufficient to meet JEN's efficient costs this may lead to penalties under the EBSS. In order to avoid such penalties JEN may need to consider capex solutions. If the level of capex is not sufficient to meet JEN's efficient costs of providing our electricity services then this option may not be open to JEN. Thus inefficient level of capex and opex may lead to penalties under both the CESS and the EBSS. If this was the case then these incentive schemes would not operate as intended and may in fact act as a disincentive to efficient investment and would not promote the Optimal NEO Position.

69. In order to promote the Optimal NEO Position an efficient level of capex and opex must be approved and the CESS incentive scheme adjusted in the manner set out in this submission.

4. SERVICE TARGET PERFORMANCE INCENTIVE SCHEME

70. The STPIS[34] is designed to create a financial incentive for network businesses to maintain and improve their service performance where consumers are willing to pay for improvements. It is also intended to work alongside the EBSS and CESS to ensure that cost efficiencies rewarded under these schemes do not arise as a result of network businesses lowering service quality for consumers.

71. The STPIS contains two measures which create incentives for improved service performance:

- A service standards factor (**s-factor**) reward (or penalty) for improved (or diminished) service compared to service targets for supply reliability and customer service
- A GSL payment scheme which requires businesses to make direct payments to consumers who experience services below pre-determined levels.

72. The s-factor component applied to our network business for the 2011 regulatory period, the GSL component has not applied because there is a Victoria-specific GSL scheme in place.[35][36]

Table 4–1: Summary of proposal and preliminary decision

Proposed parameters	JEN April 2015 proposal - reasons	Preliminary decision	JEN's response	JEN's submission
Revenue at risk	±5%	±5%	✓	Same as April 2015 proposal
GSL	Victorian jurisdictional scheme only	Victorian jurisdictional scheme only	✓	Same as April 2015 proposal
Incentive rates	Latest VCR[(1)]	Latest VCR[(1)]	✓	Same as April 2015 proposal
Targets	5 year historical average	5 year historical average	✓	Same as April 2015 proposal

(1) Australian Energy Market Operator (**AEMO**), *Value of Customer Reliability Review Final Report*, September 2014

4.1 JEN'S APRIL 2015 PROPOSAL

73. JEN proposed that the s-factor component of the STPIS continue to apply, and that its application be consistent with that set out in the F&A paper.[37] JEN outlined in Section 2 of Attachment 5-3 of its April 2015 proposal how we proposed that any STPIS specified in the F&A paper should apply to us and included information supporting that proposal.

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

35 In Victoria, the Electricity Distribution Code and Public Lighting Code set out GSLs that apply to the Victorian distributors. Essential Services Commission of Victoria, *Electricity Distribution Code, version 9 December 2015,* , p. 19; Essential Services Commission of Victoria, *Public Lighting Code*, April 2005, p. 3.

36 See Attachment 8-1 of this submission, for the treatment of GSLs.

37 AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016,* 24 October 2014, p97

74. In general, JEN adopted the approach outlined in the F&A paper except that JEN proposed that the Momentary Average Interruption Frequency Index (**MAIFI**) incentive continue as it was aligned with the STPIS objectives and aligned with the long term interests of consumers by creating stability in the use of incentive measures.

75. JEN also proposed:

- To continue the existing STPIS on seven performance measures; urban/short rural unplanned supply system average interruption duration index (**SAIDI**), urban/short rural unplanned system average interruption frequency index (**SAIFI**), urban/short rural unplanned MAIFI and telephone answering
- To set the STPIS targets on a consistent method of averaging performance over the past five years
- To continue the exclusion of the excluded events as defined in the existing STPIS clause 3.3(a) and major event days (**MED**) as defined in the existing STPIS clause 3,3(b)
- That the STPIS GSL not apply to JEN given the existing Victorian GSL scheme.

4.2 PRELIMINARY DECISION

76. The preliminary decision adopted JEN's proposed approach to the STPIS and included a scheme which:

- Sets revenue at risk at the range of ±5% with a cap on revenue at risk for the telephone answering parameter of ±0.5%
- Segments JEN's network according to feeder categories urban and short rural
- Sets applicable reliability of SAIDI**,** SAIFI, MAIFI and customer service (telephone answering) parameters
- Sets performance targets based on the JEN's average performance over the past five regulatory years
- Applies the methodology indicated in the national STPIS for excluding specific events from the calculation of annual performance targets
- Applies the methodology and latest VCR values for Victoria to the calculation of incentive rates to new investments
- Does not apply the STPIS GSL.

4.3 JEN'S RESPONSE AND THIS SUBMISSION

77. We welcome the preliminary decision's endorsement and acceptance of our proposal on the STPIS. We understand that the preliminary decision is based on maintaining consistency with the national scheme. We agree with the statement made in the preliminary decision that maintaining the scheme, consistent with the National Electricity Market (**NEM**) STPIS, will assist to ensure that:

- The incentives under the scheme are sufficient to offset financial incentives a DNSP may have to reduce costs at the expense of service levels
- That the financial rewards and penalties are consistent with the consumers' value for the service that are offered to them (subject to our comments on CESS exclusions in section 3.3.1).

78. It is consistent with the Optimal NEO Position that the financial rewards and penalties to a DNSP for service performance reflects the value consumers place on financial performance and that a DNSP does not invest less

than the amount required to achieve the outcomes that consumers are willing to pay to achieve. The VCR used to calculate the incentive rates is $39,026.67/ MWh.[38]

79. JEN agrees that the incentive rates for the reliability of supply should reflect the VCR as outlined in the STPIS[39]. However, JEN notes that the position outlined in the preliminary decision on CESS is inconsistent with its decision on STPIS. In the absence of excluding reliability improvement capex from the CESS, the STPIS and CESS will work in an inconsistent manner which will not drive consistent and sustained outcomes for efficient expenditure and the maintenance and improvement of service quality and reliability as intended by the STIPS.

80. The CESS did not apply during the 2011 regulatory period so the integrity of the incentive rate was maintained. This will not be the case during the 2016 regulatory period now that the CESS will apply.

81. The incentive rates in the preliminary decision[40] were derived from Jemena's total energy consumption for the regulatory control period, instead of, the average annual energy consumption. The STPIS[41] outline that the average annual energy consumption should be applied in calculating the incentive rates for electricity distributors. JEN believes that the method adopted in the preliminary decision is erroneous and will need to be corrected in the substituted decision so that it will have no impact on revenue for the 2016 calendar year as the performance outcomes for 2016 will be reflected in the 2018 tariffs. The corrected incentive rates will be used to calculate JEN's s-factor for its 2016 performance outcomes when the relevant data is available after April 2017.

82. JEN's submission is the same as its April 2015 proposal and aside from the calculation error, consistent with the preliminary decision. The following table outlines the incentive rates and performance targets for the STPIS to apply during the 2016 regulatory period consistent with the corrected incentive rates expected for the final decision.

Table 4–2: JEN's submission for STPIS measures, incentive rates and target values

Feeder category and performance measure	JEN April 2015 proposal		Preliminary decision		JEN Submission	
	Incentive rate[42]	Target value	Incentive rate	Target value	Incentive rate[43]	Target value
Urban SAIDI	VCR	55.401	0.36380	55.401	VCR	55.401
Urban SAIFI	VCR	0.954	21.79002	0.954	VCR	0.954
Urban MAIFI	VCR	0.756	1.74320	0.756	VCR	0.756
Rural short SAIDI	VCR	91.955	0.01863	91.955	VCR	91.955
Rural short SAIFI	VCR	1.238	1.50397	1.238	VCR	1.238
Rural short MAIFI	VCR	1.654	0.12032	1.654	VCR	1.654
Telephone answering: % of calls will be answered within 30 seconds	-0.040	64.235	-0.040	64.235	-0.040	64.235

38 AEMO, *Value of Customer Reliability Review Final Report*, September 2014.

39 AER, *Electricity distribution network service providers—Service target performance incentive scheme*, November 2009, s. 3.2.2(a).

40 AER, *Preliminary Decision Jemena distribution determination 2016-2020, Attachment 11 – Service target performance incentive scheme*, October 2015, Tables 11-1 and 11-4, pp 11-14 to 11-15.

41 AER, *Electricity distribution network service providers Service target performance incentive scheme,*, November 2009.

42 Apply the methodology and VCR values in the national STPIS to the calculation of incentive rates to past investments. For new investments, if practical amend the VCR values determined by the most recent AEMO review.

43 Same as April 2015 proposal.

4.4 INTERRELATIONSHIPS

83. There are interrelationships between the STPIS and other incentive schemes such as CESS and EBSS.

84. In order for the STPIS to operate to achieve the aims of the scheme it must:

- Be balanced and co-ordinated with the other incentive schemes
- Operate in circumstances where JEN's approved level of opex and capex enables JEN to recover at least its efficient costs of providing electricity services, complying with regulatory obligations or making a regulatory payment.

85. As indicated in Attachments 7-1 and Attachment 8-1, JEN does not consider that the preliminary decision has set capex or opex at a level which enables JEN to recover at least JEN's efficient costs. Given this, it is likely that the STPIS scheme will not work effectively or in a co-ordinated way with the CESS or EBSS to maintain or improve service performance and reliability. This would not lead to an Optimal NEO Position.

86. The interrelationships between the CESS and the STPIS are discussed in section 3.4 above.

87. In order for the STPIS to operate as designed JEN considers that the capex and opex requirements set out in JEN's submission should be accepted and the reliability improvement capex be excluded from the CESS. This would enable the STPIS to operate as an incentive to maintain and improve the performance and reliability of our electricity services without operating as a disincentive to efficient investment in JEN's network with the attendant impacts on price, quality, reliability and safety of the electricity network.

88. In order to promote the Optimal NEO Position an efficient level of capex and opex must be approved and the CESS incentive scheme adjusted in the manner set out in this submission.

5. DEMAND MANAGEMENT INCENTIVE SCHEME

89. In the 2011 regulatory period electricity distribution businesses were provided with some incentive to invest in demand management through the DMEGCIS by accessing a DMIA.

90. During the 2011 regulatory period, the NER was amended to explicitly incorporate incentives for connection of embedded generation into the DMEGCIS.[44] In its F&A paper for the 2016 regulatory period, the AER considered that the Demand Management Incentive Scheme (**DMIS**)—the version of the incentive scheme in place immediate prior to the amendments introduced in the 2011 rule change—sufficiently covers incentives to connect embedded generation[45] under the DMEGCIS.

91. The DMEGCIS is designed to provide electricity distribution businesses with financial incentives to improve the network utilisation,[46] specifically by considering alternatives to building peak network capacity (‘demand management’).[47] The DMEGCIS comprises two parts:

- Part A, which provides for an innovation allowance to be incorporated into a distribution network business’ annual revenue requirements
- Part B, which compensates a network business for any foregone revenue demonstrated to have resulted from demand management initiatives approved under Part A.

92. The preliminary decision only applies Part A of the DMEGCIS in the 2016 regulatory period. It considers that Part B is no longer appropriate, given its intention to regulate our standard control services through a revenue cap.[48]

93. Table 5–1 summarises JEN’s submission in relation to the DMEGCIS.

Table 5–1: Summary of DMEGCIS proposal and response

Parameters	JEN April 2015 proposal	Preliminary decision	JEN’s response	JEN’s submission
Scheme	Part A of DMIA	Part A of DMIA	✓	Same as April 2015 proposal
Allowance	$5.5m	$1m	✗	Same as April 2015 proposal

44 AEMC, *Rule determination, National Electricity Amendment (Inclusion of Embedded Generation Research into Demand Management Incentive Scheme) Rule 2011*, 22 December 2011

45 AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016,* 24 October 2014, p 113

46 Our network is built to provide consumers with electricity whenever and however they choose to power their homes and businesses. As the majority of our consumers use most of their electricity during “peak times” – such as weekday afternoons and evenings – our network is designed, built and maintained to meet our consumers’ needs during these peak times. Building and augmenting our network to meet peak demand is relatively costly, and so has a significant influence on our capital expenditure program and ultimately on our network prices.

47 The AER notes that demand management refers to any effort by a distributor to lower or shift the demand for standard control services, including, agreements between distributors and consumers to switch off loads at certain times and the connection of small-scale 'embedded' generation reducing the demand for power drawn from the distribution network. AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016,* 24 October 2014, p113.

48 Part B compensates network business for any foregone revenue demonstrated to have resulted from demand management initiatives approved under Part A for distributors under a weighted average price cap. Part B is not applied where distributors are subject to a revenue cap rather than a price cap.

5.1 JEN'S APRIL 2015 PROPOSAL

94. In our April 2015 proposal we proposed that only Part A of the DMIS continues to apply in the 2016 regulatory period, and that its application be consistent with that set out in the F&A paper.

95. In addition, JEN proposed that the five-year allowance provided for demand management projects increase from $1m in the 2011 regulatory period to $5.6m over the 2016 regulatory period. The projects and associated expenditure are summarised in Table 5–2.

Table 5–2: Proposed DMEGCIS projects for the 2016 regulatory period

No.	Trial Name	Benefit	2016	2017	2018	2019	2020	Total
1	Efficient connection of micro embedded generators	Remove unnecessary constraints on the connection of micro embedded generators to ultimately reduce the cost to consumers associated with capital expenditure on additional capacity			0.15	0.31	0.31	**0.77**
2	Direct load control trial	Reduce the cost to consumers associated with capital expenditure on additional capacity		0.21	0.41	0.14		**1.04**
3	Managing peak demand through customer engagement	Provide direct opportunities to consumers to reduce their bills as well as deliver lower network charges over time as the costs of providing additional capacity are deferred	0.32	0.32				**0.64**
4	Technology and economic assessment of residential energy storage	Provide direct opportunities to consumers to reduce their bills as well as deliver lower network charges over time as the costs of providing additional capacity are deferred				0.24	0.37	**0.62**
5	Distributed grid energy storage	Improve the efficiency of implementing lower cost capacity	0.67	0.74	0.74			**1.840**
6	Demand response field trial	Provide direct opportunities to consumers to reduce their bills as well as deliver lower network charges over time as the costs of providing additional capacity are deferred	0.4	0.26				**0.66**
Total			**1.09**	**1.23**	**1.31**	**0.96**	**0.67**	**5.56**

Source: April 2015 proposal, Attachment 5-5: Innovation and technology investment.

96. JEN has identified a program of demand management initiatives to:

- Develop options and flexibility for both our network and consumers through the application of demand management solutions
- Establish policy, systems, processes and staff capability that support demand management
- Where economical, resolve network supply quality and capacity constraints using demand management

97. JEN outlined in Section 6 of Attachment 5-3 and Attachment 5-5 of its April 2015 proposal the supporting information for the increase in the amount for demand management including the identified costs and timing for expenditure.

5.2 PRELIMINARY DECISION

98. The preliminary decision determined that Part A of the DMEGCIS should apply for the 2016 regulatory period. However, the preliminary decision did not accept the increased amount of DMIA of $5.6m, preferring to maintain the allowance of $200k per annum as was set in the 2011 regulatory period. The preliminary decision rejected JEN's proposed DMIA claiming:

- The DMIA should be considered at a whole of industry level, rather than each individual business
- A review of the DMIA will be undertaken during the development of the new scheme[49]
- Its approach is supported by the Consumer Challenge Panel (**CCP**) recommendation that the incentive scheme remain unchanged,[50] and the preliminary decision claims their positon is supported by consumers.

5.3 JEN'S RESPONSE AND THIS SUBMISSION

99. We welcome the preliminary decision's endorsement and acceptance of the continued application of Part A of the DMIA as this is consistent with providing continued incentives for DNSPs to develop innovative non-network solutions which can reduce the costs to consumers in the short and long term. We also welcome the endorsement and acceptance of the importance of demand management in deferring the need for network augmentation by alleviating network utilisation during peak usage periods.

100. However, we do not agree with the preliminary decision to maintain the $1m allowance of the DMIA. We consider this amount has been arbitrarily set, is unnecessarily low, has acted as a constraint on opportunities for connecting embedded generation, unnecessarily defers benefits to consumers and does not adequately address the proposal put forward by JEN.

101. JEN's proposal to increase the DMIA amount to $5.6m was based on the costs of an identified set of projects that JEN considers will assist it to develop strategies to manage demand, in particular peak demand, and are therefore in the long term interest of JEN's consumers.

102. Taking proactive steps to manage demand, particularly peak demand, was identified by our consumers as an important initiative which they would like JEN to continue to explore.[51]

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[49] AEMC, *Rule determination, National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015*, 20 August 2015

[50] AER, *Preliminary decision, Jemena distribution determination 2016 to 2020, Attachment 12 – Demand management incentive scheme*, October 2015, p 12-9

103. JEN considers that these projects promote the Optimal NEO Position because they all examine how demand can be better managed and thus enable JEN to explore non-network solutions. This may reduce the cost of providing electricity services to our consumers without impacting quality, safety, reliability or security of the electricity system and thus has the potential to deliver benefits to JEN's consumers over the long term. JEN presented, in its April 2015 proposal, its DMEGCIS trial program for the 2016 regulatory period. The preliminary decision will mean that JEN will not be able to deliver most of these projects.

5.3.1 REASONS FOR REJECTION OF INCREASED DMIA LEVELS

104. In response to the reasons provided in the preliminary decision for rejecting JEN's proposal for an increase in the value of the DMIA JEN notes:

5.3.1.1 Stakeholder views

105. The preliminary decision states that the CCP recommended that the DMIA scheme remain unchanged. However at the AER's public forum on the preliminary decision (17 November 2015), the CCP stated that the AER's characterisation of their opposition to higher DMIA allowances was not accurate and that they supported higher incentives.

106. As set out above JEN's consumers support demand management initiatives. As the DMIA is a 'use it or lose it' scheme, allowing funding of higher demand management and innovation activities will promote the Optimal NEO Position because consumers will only pay for the demand management that the distribution business actually spends. Further, as DMIS expenditure is subject to ex-ante or ex-post review consumers will not be exposed to imprudent or inefficient DMIS expenditure.

5.3.1.2 Industry wide investment

107. JEN does not agree with the preliminary decision's assertion that the amount provided for demand management initiatives should only be revised at an industry wide level. To wait a further five years to improve incentives in Victoria does not promote an Optimal NEO Position and is not consistent with what JEN's consumers want and what they consider to be in their long term interests.

108. Whilst there are some similarities between JEN's proposed projects and those proposed by AusNet Services and United Energy (for example, each of the businesses have proposed trials for the control of customer appliances such as air conditioners and pool pumps; trials that encourage customer behavioural change such as incentive payments and innovative tariffs; and both AusNet Services and JEN have proposed residential battery trials) there are some important differences between the trials. For example:

- AusNet Services trial will focus on remote community power supply and a number of new technology trials and developments
- United Energy has a focus on specific regions within their supply territory (Doncaster, Monash University Campus)
- Jemena's trial focuses on a broader spectrum of its customer base and is specifically pursuing an embedded generation connection initiative which none of the other businesses have proposed.

109. While there are opportunities for the DNSPs to cooperate in joint trials and developments, there are differences in demographic, social and network characteristics between the electricity networks which warrant individual focus. JEN considers that the AER should therefore give consideration to our proposal to increase the DMIA to enable JEN to undertake the specific projects identified in our April 2015 proposal and this submission.

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[51] See *Attachment 1-4: Continuing engagement with our customers* to this submission, p.11

5.3.1.3 A review of the DMIA will be done during the development of the new scheme - benefits to consumers unnecessarily deferred

110. Delaying an increase in the amount of the DMIA means that:

- The benefits to consumers over the 2016 regulatory period will be inhibited if the DMIA is not increased because most of the projects are trial programs designed to improve the knowledge around the cost and benefits of the program and build JEN's capabilities for efficiently integrating demand management in the network. These trials are a necessary precursor to deliver larger benefits in future years. The trials will also enable the programs to be tested against consumer preferences and to enable JEN to consider the effectiveness of consumer education and participation. Not undertaking the trials, or delaying the trials, will delay or prevent the benefits from being realised—or not being realised at all—this leads to less efficient and effective implementation of further programs. This is inconsistent with the objective of the scheme
- The benefits of any demand management initiatives are likely to be stifled throughout the whole of the 2016 regulatory period as the scheme developed by the AEMC will not take effect until 2021 thus deferring progress on, and the benefits of, demand management, for a further five years to the detriment of consumers and contrary to the Optimal NEO Position
- Technology in this area is moving very quickly and to apply timeframes which delay implementation of new solutions by at least 5 years is not in the interests of consumers. The benefits of fast moving technology can be maximised by decreasing the current constraints on investment to utilise and integrate these technologies. The DMIA scheme was introduced and developed as a result of acknowledging the limited incentives for network businesses to pursue these initiatives and capture the opportunities under the current economic regulation framework
- It would seem arbitrary and unnecessary to constrain the opportunities that technology can bring over the next five years pending a review of the scheme which, based on experience to date in Australia and elsewhere (where initiatives have been undertaken and actively pursued), are likely to result in an increased allowance for each business and potentially provide an even greater allowance across the industry.

5.3.1.4 Level arbitrarily set and too low

111. An inappropriate use of the inventive framework—by setting the allowance too low—would cause inefficient outcomes and therefore not promote the Optimal NEO Position.

112. The DMIA established in the initial scheme[52] was set at a level which was proportional to revenue. Whilst this may have been appropriate for the initial scheme JEN considers that it is not the correct allowance for an effective incentive. This amount has served only as a placeholder to trial the scheme. However, JEN has demonstrated its commitment to pursuing innovative demand management initiatives and has invested $1.1m during the 2011 regulatory period—slightly more than the allowance provided for the period.

113. So whilst a constraint on the amount of the DMIA may have been appropriate for the first trial period of the scheme; JEN considers that retaining the constraint will limit the pursuit of additional projects that will deliver benefits to consumers. JEN has identified specific projects that would be undertaken under the scheme if the constraint is lifted to the level set out in JEN's proposal.

114. The original scheme allowance was set based on a distribution businesses' scale. However, JEN submits that the allowance should take into account the specific programs proposed by the businesses. Many demand

[52] The scheme in force during the 2011 regulatory period

management trials have fixed costs and do not scale with the size of the network. Finally, consideration of the costs of a typical demand management project or program is a part of the current scheme.[53]

115. Since 2011, the scheme has been expanded to cover the connection of embedded generation however this has not been factored in to the size of the allowance. With a broader coverage the allowance has in fact been reduced in real terms.

116. Many demand management trial opportunities are now available after completion of the advanced metering infrastructure (**AMI**) rollout but restriction on funding means the opportunities may not be pursued. These opportunities are unlikely to be realised in the absence of a sufficient DMIA resulting in the inability to realise further benefits from the AMI program.

5.3.2 APPROACH IS SUPPORTED BY OUR CONSUMERS

117. As outlined above, JEN has identified specific projects which have been presented, consulted on and considered by JEN's consumers as part of this review process. The preliminary decision has not identified any benefits of delaying a revision to the allowance until the next regulatory period contrary to the wishes of JEN's consumers. JEN considers that there is no benefit and that JEN's consumers are not assisted by the preliminary decision.

118. Further, in its submission, the CCP did not recommend that the DMIA amount should not be revised or that any revision should occur through a future process. Specifically, the CCP recommended[54]

> *"The AER should carry out an overall assessment of the DMIA to ensure that there is no duplication of projects across the NEM, and that all projects provide a benefit to consumers."*[55]

119. It appears that the preliminary decision has taken this recommendation to mean that the review should not occur as part of the current preliminary decision. JEN considers that the current process is appropriate and the AER has sufficient information to undertake such a review. In any event, JEN's consumers support an increase in the amount and the proposed projects[56] and this information should be given at least the same weight to informing a decision as any submissions from the CCP.

120. As outlined in Attachment 4-1 of our April 2015 proposal consumers and stakeholders told us that in relation to demand management initiatives:

- They think we should be proactive in exploring trials of new technologies and other programs which can help lower costs over the long-term
- They thought we should consider offering incentives for consumers to reduce their usage at peak times
- In the case of local governments and some large consumers, they would like the opportunity to participate in demand management trials and projects. This preference was further reiterated in JEN's customer council meeting following the release of the preliminary decision (see Attachment 1-3 of this submission).

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53 AER, *Demand management incentive scheme – Jemena, CitiPower, Powercor, SP AusNet and Unite d Energy: 2011-15*, April 2009, p. 5.

54 Consumer Challenge Panel Sub Panel 3, *Response to proposals from Victorian electricity distribution networks service providers for a revenue rest for the 2016-20 regulatory period*, 10 August 2015, p. 10.

55 CCP, *Submission to the Australian Energy Regulator (AER), An overview Consumer Challenge Panel Sub Panel 3 (CCP3) Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016 - 2020 regulatory period*. 10 August 2015, p. 11.

56 April 2015 proposal, Attachment 4-1, p 48.

121. This investment will enable JEN to ensure that consumers can continue to provide input into, influence and benefit from the programs being undertaken across the industry.

5.3.3 INTERACTIONS OF OTHER INCENTIVE SCHEMES

122. JEN is dis-incentivised to invest at levels above the allowance because of the workings of the EBSS and CESS schemes. Expenditure in excess of the DMIA will be classified as opex or capex. Thus for each dollar spent over the DMIA not only is JEN self-funding the initiative but it is also penalised through the EBSS and CESS incentive schemes.

123. During the 2016 regulatory period the risk is greater for two reasons:

- the CESS scheme has been introduced
- an ex-post review of capex, not in place in the 2011 regulatory period, could result in capex being disallowed for inclusion in the RAB, something to be avoided by not over investing in demand management capex initiatives.

124. Whilst network businesses can absorb small amounts of risk the framework perversely inhibits this and therefore the DMIA must be set at a level to cover the risks arising from the interactions of the other incentive mechanisms.

5.3.4 JEN'S SUBMISSION

125. JEN maintains in this submission that the allowance under the DMIA should be set to $5.6m to allow JEN to deliver the initiatives that it has specifically outlined in Table 5–2. The continued pursuit of these initiatives will promote the Optimal NEO Position.

5.4 INTERRELATIONSHIPS

126. The DMIA scheme interrelates with the EBSS and CESS in that any amounts spent in excess of the DMIA amounts could lead to penalties under the EBSS and CESS as described above.

127. By setting the level of DMIA artificially low and the level of capex and opex at a level below JEN's efficient costs the preliminary decision has severely curtailed, or prevented entirely, JEN undertaking the demand management initiatives which JEN's consumers want JEN to undertake. This does not promote the Optimal NEO Position.

6. F-FACTOR SCHEME

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

129. Under an Order-in-Council made by the Victorian Government, the AER must make various decisions under the f-factor scheme, including setting:

- A fire start target for each network business
- The incentive rate to reward (or penalise) each business for performing better (or worse) that its target.

130. Under the scheme, the total reward (or penalty) over a regulatory period is added to (or subtracted from) the business' annual revenue requirements for the next regulatory period.[57] For the 2011 regulatory period, the preliminary decision set our incentive rate at $25,000 (nominal value) per fire start better or worse than our fire start target. While the AER may vary the incentive rates for the 2016 regulatory period, it has made a decision to maintain the incentive rate of $25,000 per fire in its preliminary decision pending a review by the Victorian Government.

131. Table 6–1 summarises JEN's submission on the f-factor scheme.

Table 6–1: Summary of F-factor scheme proposal and response

Proposed exclusions from the scheme	JEN April 2015 proposal - reasons	Preliminary decision	JEN's response	JEN's submission
Target method	Based on an average over three years (2012-2014)	Based on 5 years historical average	✓	Accept approach from the preliminary decision
Target	72.3	66.1	✓	Accept the target in the preliminary decision
Incentive rate	$25,000	$25,000	✓	Same as April 2015 proposal

6.1 JEN'S APRIL 2015 PROPOSAL

132. We proposed that the scheme outlined in the F&A paper[58] be adopted by including the incentive rates as determined for the 2011 regulatory period. However, we proposed that the target increase to 72.3 from 56.8 to reflect an average over the 2012-2014 period because:

- In our network area, in the three years prior to 2012 (ie. 2009-2011) we faced an abnormally high amount of rain, which is reflected in a significantly reduced number of pole top fire starts in the JEN area and across Victoria. As our pole top fires represent approximately 80% of all fire starts, if a target is derived using abnormal years, this will set an unachievable target

[57] These rewards or penalties are added or subtracted as a pass-through amount in calculating the annual revenue

[58] AER, *Final framework and approach for the Victorian Electricity Distributors, regulatory control period commencing 1 January 2016*, 24 October 2014.

- JEN outlined in section 3 of Attachment 5-3 of our April 2015 proposal the supporting information for its April 2015 proposal for the Fire Factor scheme.

6.2 PRELIMINARY DECISION

133. The preliminary decision did not approve JEN's f-factor scheme because the AER did not consider that it was consistent with the F&A and JEN's suggested change would require a change to the scheme and, as such, should be done separately from the regulatory decision process.

134. The preliminary decision rejected JEN's proposed targets and instead applied a target of 66.1 per year based on a five year historical average calculated based on:

- The fire starts data for 2012–2014 from the f-factor RIN
- For 2010 and 2011, the fire starts target under the previous scheme due to audited fire start information not being available for 2010 and 2011.

135. The preliminary decision noted that the scheme's design will likely be significantly modified by the Victorian Government in 2016[59].

6.3 JEN'S RESPONSE AND THIS SUBMISSION

136. We have incorporated into our submission the method form the preliminary decision to develop a five-year historical average target by substituting the fire start target for the previous scheme where audited data is not available.

[59] AER, *Preliminary decision Jemena distribution determination 2016 to 2020 Attachment 18 – F-factor scheme*, October 2015, p. 18-7.