Jemena Electricity Networks (Vic) Ltd

Victorian 2016-2020 Electricity Distribution Process Review

Submission to the Victorian EDPR Process

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TABLE OF CONTENTS

List of tables

List of appendices

GLOSSARY

6 January submission	Jemena Electricity Networks (Vic) Ltd, Revocation and substitution submission, 6 January 2016
CBA report	Report prepared by Deloitte, *Advanced metering infrastructure cost benefit analysis*, 2 August 2011
Minister's July submission	Victorian Department of Economic Development, Jobs, Transport & Resources – Submission to Victorian electricity distribution pricing review – 2016 to 2020
Minister's submission	Victorian Government, "Submission on the Victorian electricity distribution network service providers' preliminary distribution determinations for 2016-20"
Ofgem determination	Ofgem's RIIO-ED1: Final determinations for the slow-track electricity distribution companies; Overview; Final Decision, dated 28 November 2014
submission	JEN's submission to the Victorian EDPR public submission process, dated 4 February 2016

ABBREVIATIONS

AEMC	Australian Energy Markets Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
CAM	Cost Allocation Method
CMA	United Kingdom Competition and Markets Authority
DEDJTR	Victorian Government Department of Economic Development, Jobs, Transport and Resources
DGM	Dividend Growth Model
DMIA	Demand Management Incentive Allowance
DNSP	Distribution Network Service Provider
DRP	Debt Risk Premium
EAGA	Eastern Alliance for Greenhouse Action
EDPR	Electricity Distribution Price Review
ERP	Equity Risk Premium
ESC	Essential Services Commission
GFN	Ground Fault Neutralisers
GSL	Guaranteed Service Level Payments
JEN	Jemena Electricity Networks (Vic) Ltd
MAIFI	Momentary Average Interruption Frequency Index
MRP	Market Risk Premium
NAGA	Northern Alliance for Greenhouse Action
NEO	National Electricity Objective
NER	National Electricity Rules
NPg	Northern Powergrid Group
Ofgem	United Kingdom Office of Gas and Electricity Markets
PTRM	Post-tax Revenue Model
RAB	Regulated Asset Base
REFCL	Rapid Earth Fault Current Limiting
RIN	Regulatory Information Notice
SCS	Standard Control Services
SGB	Smart Grids Benefits
SL CAPM	Sharpe Lintner Capital Asset Pricing Model
STPIS	Service Target Performance Incentive Scheme
SUPS	Substation Utilisation Profiling System

VCR	Value of Customer Reliability
VECUA	Victorian Energy Consumer and User Alliance

OVERVIEW

1. On the 6 January 2016 Jemena Electricity Networks (Vic) Ltd (**JEN**) lodged a submission to the Australian Energy Regulator's (**AER**'s) revocation and submission process for the Victorian Electricity Distribution Price Review (**EDPR**). This was made in response to the AER's Preliminary Decision (made on 29 October 2015) on JEN's initial regulatory proposal (submitted to the AER on 30 April 2015). During this period, submissions by interested stakeholders were also made to the AER on its Preliminary Decision.

2. On its website the AER has invited comments on the submissions made by the Victorian distributions businesses and an invitation to the Victorian distribution businesses to provide comments on submissions made by third party stakeholders on the AER's Preliminary Decision:[1]

> *Interested third party stakeholders are invited to comment on the Victorian distributors' revised regulatory proposals by 4 February 2016. By the same date, we will allow further submissions from all stakeholders, including the distribution businesses, on the submissions made by third party stakeholders to the preliminary decisions.*

3. JEN is making this submission (**submission**) in response to matters raised by interested stakeholders who submitted on the AER Preliminary Decision.

4. The matters we are responding to are outlined in Table OV–1.

Table OV–1: Summary of JEN's response to topics raised interested parties

Topic	Interested stakeholder	Issue
Rate of return	The Victorian Energy Consumer and User Alliance (**VECUA**)[2] and Origin Energy[3]	Each submission claims the rate of return is too high.
Demand Management Incentive Allowance (**DMIA**)	A joint submission by Northern Alliance for Greenhouse Action (**NAGA**) and Eastern Alliance for Greenhouse Action (**EAGA**)[4]	Supports a higher allowance for demand management initiatives.
Benefits realisation through the Advanced Metering Infrastructure (**AMI**) roll-out	The Minister for Energy and Resources on behalf of the Victorian Government (**Minister's submission**)[5]	Proposes efficiency gains–derived from the AMI rollout program–should be passed onto customers in the form of a lower revenue allowance.
Customer contributions for new connections	Minister's submission	References the treatment of the x-factor in 2020 and the implications for calculating the customer contributions. The Minister's submission also highlights the transition to the National Electricity Rules (**NER**) chapter 5A for calculating customer contributions.

1 http://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/jemena-determination-2016-20/revised-proposal

2 VECUA, "Submission to the AER, AER Preliminary 2016-20 Revenue Determinations for the Victorian DNSPs", 6 January 2016

3 Origin Energy, "Submission to AER preliminary decision Victorian networks", 6 January 2016

4 NAGA and EAGO, "Victorian Electricity Distribution Price Review 2016-20 Preliminary Decision October 2015", 6 January 2016.

5 Victorian Government, "Submission on the Victorian electricity distribution network service providers' preliminary distribution determinations for 2016-20", [undated].

Topic	Interested stakeholder	Issue
Operating expenditure step change – Vegetation Management	Minister's submission	Questions the operating expenditure step change for vegetation management sought by the Victorian distribution businesses.
Guaranteed Service Level (**GSL**) payments	Minister's submission	Notes changes to the Victorian Essential Services Commission's (**ESC**) GSL scheme that should be accounted for in the AER's substitute determination.
Rapid Earth Fault Current Limiter (**REFCL**) impacts on Service Target Performance Incentive Scheme (**STPIS**) targets	Minister's submission	Seeks to adjust the STPIS targets to account for the reliability benefits attributed to the installation of REFCL devices to ensure customers do not pay twice or these devices.
Cost allocation between standard control services (**SCS**) and metering services	Minister's submission	Highlights risks of not allocating the costs between metering and SCS correctly.

5. As a part of this submission, JEN also includes a suite of revised models to give effect to the changes arising from JEN's response to the items raised by interested parties, these are listed in Table A1–2.

1. RATE OF RETURN

1.1 VECUA'S SUBMISSIONS IN RELATION TO JEN'S RATE OF RETURN PROPOSAL

6. VECUA sets out a number of concerns with JEN's rate of return proposal and supporting submissions. JEN has now provided (on 6 January 2016) a comprehensive response to the Preliminary Decision, which addresses each of the issues raised by VECUA.

7. In particular:

- in response to concerns regarding the multi-model approach, JEN has put forward an alternative approach to estimating the return on equity which relies on the Sharpe Lintner Capital Asset Pricing Model (**SL CAPM**) alone but with appropriate adjustments to account for known weaknesses in this model; and

- JEN has also revised its approach to estimating the return on debt, adopting a simpler approach of transitioning immediately to the trailing average method.

8. JEN considers that each of the concerns previously expressed by the AER and stakeholders have now been addressed in the submission and supporting evidence submitted on 6 January 2016.

1.2 VECUA'S SUBMISSIONS ON THE AER'S WACC DETERMINATION APPROACH

1.2.1 INSUFFICIENT CONSIDERATION OF MARKET DATA AND OTHER EVIDENCE

9. JEN agrees with VECUA that the AER has had insufficient regard to market evidence in determining the rate of return. However JEN does not agree with VECUA's submission that a proper consideration of available market data and other evidence would support a lower rate of return than that determined by the AER.

10. On the contrary, as noted in JEN's 6 January submission:[6]

- the AER's estimate of the return on equity is below any comparable recent estimate from market practitioners, including estimates from the AER's review of recent broker reports and independent expert reports; and

- the AER's estimate of the return on equity is below that indicated by current market prices for traded equities and the AER's market-wide dividend growth model (**DGM**) analysis.

11. This outcome is due to the AER mechanistically applying the foundation model approach developed in the Rate of Return Guidelines, without any meaningful consideration of whether such an approach leads to an estimate of the return on equity that is consistent with the allowed rate of return objective and commensurate with prevailing market conditions.

12. More specifically, this is the result of the AER:

- relying solely on the output of a model that is known to produce biased estimates, without properly correcting for that bias;

6 JEN, Revocation and substitution submission – Attachment 6-1 Rate of return, gamma, forecast inflation, and debt and equity raising costs, 6 January 2016, pp 44-45

- applying this model in a way that does not reflect market practice and which results in the return on equity simply tracking movements in the risk-free rate; and
- making errors in the interpretation of key evidence.

13. Further evidence provided with this submission reinforces these points. Evidence from investors indicates that the AER's proposed return on equity of 7.3% is not too high, as suggested by the VECUA submission, but rather it is too low.

14. A submission made by listed infrastructure fund Spark Infrastructure in relation to the AER's April 2015 preliminary determination for SA Power Networks explains that:

- the regulatory returns resulting from the AER's implementation of the SL CAPM using short term base rates and long run average market risk premium are well below the prevailing market rates;[7]
- the AER's approach of combining short term base rates and long run average market risk premium in the SL CAPM is inconsistent with market practice in relation to estimation of hurdle rates for investment;[8] and
- the returns allowed in the AER's latest determinations are not sufficient to attract equity investment when compared to competing investment opportunities.[9]

15. Spark's view has been informed by feedback from a broad range of pension funds and other ultimate suppliers of investment funds. Their feedback to Spark was universally that the regulatory returns currently expected for the next regulatory periods are inadequate to sustain long run decisions to invest in the sector.[10]

16. The statements made by Spark Infrastructure in its submission in relation to the AER's April 2015 determinations remain apposite in this case. In the Preliminary Decision in respect of JEN, the AER has applied the same method for estimating the return on equity as it applied in the April 2015 determinations, and the resulting return on equity estimate is very similar (7.3% compared to 7.1%).

1.2.2 THE AER'S FOCUS ON JEN'S PROPOSAL

17. JEN does not agree that the AER has "inappropriately" focused on the rate of return proposals put forward by the Victorian businesses.

18. JEN and the other Victorian businesses have provided cogent evidence as to the required return of equity and return on debt for the forthcoming regulatory period. It is entirely appropriate (and required under the NER) for the AER to have proper regard to this evidence.

19. JEN considers that in fact the AER has not sufficiently had regard to all of the evidence it has submitted to date. In particular, the AER does not appear to take into account the estimates of the return on equity provided by Frontier Economics using the Black CAPM, the Fama French Model and DGM. Rather, the AER has solely relied on its implementation of the SL CAPM to determine the return on equity.

1.2.3 IMPLICATIONS OF THE RECENT TRANSGRID SALE

20. VECUA submits that the outcome of the recent TransGrid sale process "makes a mockery" of claims made by network service providers regarding the required return on equity.[11] VECUA appears to consider that the fact

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[7] Spark Infrastructure, *Appropriate rate of return for electricity distribution businesses*, 3 July 2015, p 2.

[8] Spark Infrastructure, *Appropriate rate of return for electricity distribution businesses*, 3 July 2015, p 4.

[9] Spark Infrastructure, *Appropriate rate of return for electricity distribution businesses*, 3 July 2015, p 5.

[10] Spark Infrastructure, *Appropriate rate of return for electricity distribution businesses*, 3 July 2015, p 2.

that the agreed sale price for TransGrid exceeds its regulated asset base (**RAB**) value indicates that the return on equity allowed by the AER for TransGrid (7.1%) is at least sufficient for it to meet efficient financing costs and attract equity investment.

21. This issue is addressed in the accompanying expert report of Frontier Economics.[12]

22. Frontier Economics conclude that the fact that the TransGrid sale price exceeded the RAB value does not constitute any evidence of the adequacy of the AER's allowed return on equity of 7.1% for the remaining four years of the current regulatory period. The reasons for this conclusion include:[13]

- the sale price reflects not only the allowed return on equity of 7.1% for the next four years, but also a range of other factors, including:
  - expected cash flows over the full 99-year lease period;
  - the extent to which the acquirer considers that it may be able to outperform regulatory benchmarks under incentive-based regulation or be eligible to receive incentive payments (e.g. its expected ability to achieve operating efficiencies);
  - the acquirer's assessment of the value attributed to non-regulated assets owned by TransGrid;
  - the potential for future growth in the earnings of the firm over the 99-year lease period, arising from: the expansion of existing non-regulated activities; the development of new non-regulated activities; and/or increasing the scale and/or efficiency of regulated activities;
  - any synergies with the acquirer's existing business;
  - any diversification benefits available to the acquirer;
  - any strategic value to the acquirer (e.g. value in seeking to establish an operation in a new market or reach an efficient scale in a market where it already has some interests); and
- since controlling interests are purchased at a material premium to ordinary equity, the prices paid for controlling interests cannot be used to infer anything about the required return on ordinary equity – even aside from the other reasons set out above.

23. Frontier also notes that the return on equity allowance of 7.1% recently determined by the AER for TransGrid only applies for four years of the 99-year lease period, and that beyond this four-year period it may reasonably be assumed that allowed returns would return to more acceptable levels. This could occur either as a result of a change in the AER's methodology (e.g. following a rule change or Tribunal ruling against the current AER method) or continuation of the AER's current methodology in different market conditions (i.e. with a higher risk-free rate, leading to a higher return on equity under the AER's method).

24. The TransGrid equity investment prospectus published by Spark Infrastructure (referred to in the VECUA submission) confirms the above analysis. This prospectus does not indicate that the regulated return on equity allowed for TransGrid for the next four years is a driver of the agreed sale price or of the acquirer's perception of the value of TransGrid – the only comment that is made about this is that "TransGrid's current regulatory

[11] VECUA submission, p 14.

[12] Frontier Economics, *Response to submissions on the relevance of the TransGrid sale*, February 2016.

[13] Frontier Economics, *Response to submissions on the relevance of the TransGrid sale*, February 2016, pp 4-5.

determination applies for 4 years only (to 30 June 2018) and was not appealed by its previous owners”.[14] Rather, the prospectus identifies other areas of value in the TransGrid business as including:[15]

- strategic benefits for Spark in increasing diversity of cash-flow sources, thereby reducing overall portfolio risk;
- scope to increase efficiency through better asset utilisation and process improvements;
- scope for long term growth in regulated activities (and hence RAB growth), supported by macro-economic driven demand growth expectations, and change in generation mix to renewables;
- Spark’s ability to leverage TransGrid’s assets and apply its own expertise to develop and grow non-regulated business opportunities. The prospectus notes in particular some scope to grow a telecommunications service offering that leverages TransGrid’s market positioning across NSW.

25. Therefore, consistent with previous conclusions of the AER[16] and its experts,[17] JEN considers that nothing can be inferred from the outcome of the TransGrid sale process, as to the adequacy or otherwise of the regulated return on equity for TransGrid or any other business.

1.3 VECUA’S SUBMISSIONS ON THE AER’S WACC DETERMINATIONS

1.3.1 RELEVANCE OF ASSET INDEXATION TO THE AER’S RETURN ON EQUITY DETERMINATION

26. VECUA argues that the AER has failed to consider the impact of asset indexation in its return on equity determinations. It is said that the AER’s calculation of its return on equity allowances does not reflect the reality that networks apply annual asset indexation to their regulatory asset bases (**RABs**).

27. This is not correct. The method adopted by the AER for determining annual revenue requirements does take into account the fact that, under the NER, the RAB must be indexed each year for inflation[18] and a nominal rate of return must be applied to this indexed RAB value to determine the return on capital allowance.[19] This is accounted for by making an adjustment to the annual revenue requirement calculation for each year for indexation of the regulatory asset base, as required by the NER.[20] The adjustment that is made to the annual revenue requirement is a negative adjustment equal to the amount by which the RAB is indexed for inflation in that year.[21]

28. Therefore, no further adjustment to the method for dealing with inflation is required, nor would any further adjustment be permitted under the NER. As explained above, the NER clearly prescribe how inflation is to be accounted for in determining the rate of return (i.e. the rate of return is to be determined on a nominal basis), rolling forward the RAB (the RAB is to be adjusted for inflation in each year) and determining revenue requirements (the annual revenue requirement is to include a negative adjustment for indexation of the regulatory asset base).

14 Spark Infrastructure, *Equity Investment in TransGrid and Equity Raising*, 25 November 2015, p 26.

15 Spark Infrastructure, *Equity Investment in TransGrid and Equity Raising*, 25 November 2015, pp 9-10.

16 AER, *Rate of Return Guideline Explanatory Statement*, December 2013, p 48.

17 McKenzie and Partington, *Equity market risk premium*, December 2011, p 34.

18 NER cl 6.5.1; S6.2.3(c)(4).

19 NER, cl 6.5.2(d)(2).

20 NER, cl 6.4.3(a)(1).

21 NER, cl 6.4.3(b)(1).

29. As discussed in JEN's 6 January submission, this gives rise to important interrelationships between the method for forecasting inflation and other aspects of the AER's determination, particularly its determination of the allowed rate of return. Given these interrelationships, it is important that the forecast of inflation be as accurate as possible, and consistent with the implied forecast of inflation in the nominal rate of return. This issue is discussed further in JEN's 6 January submission.[22]

1.3.2 ESTIMATION OF THE RETURN ON EQUITY

30. VECUA argues that the AER has over-estimated the return on equity, by applying a market risk premium (**MRP**) and equity beta in the SL CAPM that are too high. VECUA argues that both the MRP and equity beta should be set to the bottom of the AER's ranges for those parameters (i.e. 5% and 0.4 respectively).

31. VECUA's submissions on the return on equity rest on the following contentions:

- that it is appropriate to use the SL CAPM alone to estimate the return on equity, with no adjustment for any of the known weaknesses in this model;
- best estimates of the MRP and equity beta are 5% and 0.4 respectively; and
- using an MRP of 5% and equity beta of 0.4 in the SL CAPM will lead to a reasonable estimate of the return on equity, and one that contributes to the achievement of the allowed rate of return objective.

32. For reasons set out in the JEN's 6 January submission, the evidence before the AER does not support the first contention. The empirical evidence points to shortcomings in the design of the SL CAPM which mean that it will underestimate the required return on equity for businesses with a beta below one and businesses with high book-to-market ratios.[23]

33. VECUA's submission as to the best estimates of the equity beta and MRP are also not supported by the evidence before the AER. No expert (including the AER's expert) concludes that the best empirical estimate of the equity beta is 0.4;[24] rather, the expert evidence supports an SL CAPM equity beta of 0.82 (before any adjustment to account for biases in this model).[25] Similarly, the expert evidence before the AER does not support an MRP of 5%, but rather supports a much higher estimate of the prevailing MRP (Frontier Economics recommend an estimate of 7.9%).[26]

34. Finally, VECUA's submissions do not include any consideration of whether the return on equity and overall rate of return that would result from its proposed approach is reasonable and consistent with the allowed rate of return objective. If VECUA's proposal were to be implemented, this would deliver an equity risk premium (**ERP**) of just 2% and a return on equity of approximately 4.8%. This is significantly below the ERP and return on equity ranges indicated by the reasonableness checks (or "cross-checks") referred to by the AER in the

[22] JEN, Revocation and substitution submission – Attachment 6-1 Rate of return, gamma, forecast inflation, and debt and equity raising costs, 6 January 2016, pp 116-117.

[23] Refer to: JEN, Revocation and substitution submission – Attachment 6-1 Rate of return, gamma, forecast inflation, and debt and equity raising costs, 6 January 2016, section 3.3.

[24] VECUA refers to "Professor Henry's estimate of 0.4". Professor Henry did not recommend an estimate of 0.4. Rather, Professor Henry recommended a range of 0.3 – 0.8, based in the limited sample of domestic businesses that he was instructed to use (Olan T Henry, *Estimating β: An update*, April 2014, p 63).

[25] Frontier Economics, *Estimating the equity beta for the benchmark efficient entity,* January 2016. See also: JEN, Revocation and substitution submission – Attachment 6-1 Rate of return, gamma, forecast inflation, and debt and equity raising costs, 6 January 2016, section 3.4.3.

[26] Frontier Economics, *The required return on equity under a foundation model approach*, January 2016, Table 5. See also: JEN, Revocation and substitution submission – Attachment 6-1 Rate of return, gamma, forecast inflation, and debt and equity raising costs, 6 January 2016, section 3.4.2.

Preliminary Decision.[27] VECUA's submission would also imply a return on equity that is significantly below the prevailing return on debt.

35. The relevant evidence in relation to each of these issues is addressed in detail in JEN's 6 January submission.

1.3.3 RETURN ON DEBT

36. VECUA raises two issues in relation to estimation of the return on debt:

- VECUA claims that, by using broad BBB data series for estimation of the return on debt, the AER has provided significantly higher cost of debt allowances than appropriate; and
- VECUA argues that the AER should benchmark businesses' actual debt costs to inform its return on debt allowances.

37. The first of these issues was addressed in JEN's 6 January submission. For reasons explained in that submission, continuing to use a broad BBB band data series to estimate the return on debt will not lead to an allowance that is 'too high'. Rather, given that the evidence supports a credit rating of BBB to BBB+, using a broad BBB band data series is entirely appropriate.[28]

38. In relation to the second issue, JEN submits that it would not be appropriate, and not consistent with the NER and NGL, for the return on debt allowance to be based on businesses' actual debt costs. Such an approach would be inconsistent with:

- the allowed rate of return objective, which requires the rate of return to be commensurate with the efficient financing costs of a benchmark efficient entity (not the actual financing costs of the regulated business);[29]
- the revenue and pricing principles, which provide for recovery of at least the efficient costs incurred in the provision of direct control network services (not actual costs) and the provision of effective incentives to promote economic efficiency;[30]
- the national electricity objective, which is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers;[31] and
- the principles of incentive-based regulation, including that service providers should be compensated for the efficient costs of service delivery (not actual costs), so that at least some of the rewards or penalties associated with over- or under-performance against the efficient cost benchmark flow to the service provider.

39. As has been recognised by policy-makers and the AER on numerous occasions, in order to promote efficient investment in, and efficient operation and use of, regulated services, businesses should be compensated for the efficient cost that would be incurred by the relevant benchmark efficient entity. Setting regulated allowances based on actual costs potentially provides businesses with a perverse incentive to inflate their actual costs.

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27 For an analysis of these cross-checks, refer to: JEN, Revocation and substitution submission – Attachment 6-1 Rate of return, gamma, forecast inflation, and debt and equity raising costs, 6 January 2016, section 3.5.

28 JEN, Revocation and substitution submission – Attachment 6-1 Rate of return, gamma, forecast inflation, and debt and equity raising costs, 6 January 2016, pp 28-29.

29 NER, cl 6.5.2(c).

30 NEL, s 7A.

31 NEL, s 7.

40. This was explained by the Australian Energy Markets Commission (**AEMC**) is its final rule determination accompanying the November 2012 changes to the rate of return rules. The AEMC stated (referring to statements in its draft rule determination which were affirmed in the final determination):[32]

> *"The draft rule determination stated that the primary objective of the allowed rate of return is to provide service providers with a return on capital that reflects efficient financing costs. A rate of return that reflects efficient financing costs will allow a service provider to attract the necessary investment capital to maintain a reliable energy supply while minimising the cost to consumers. The Commission also stated that it is important for recovery of financing costs to be based on benchmark efficient finance costs. This is to provide incentives for firms to adopt efficient financing arrangements and to protect consumers from the effects of inefficient ones."*

41. Specifically in relation to the return on debt, the AEMC stated:[33]

> *The return on debt allowance must still be estimated in a manner consistent with the overall rate of return objective. That is, it must be a benchmark cost of debt for an efficient firm. It should not be misinterpreted as suggesting that it must reflect a service provider's actual cost of debt.*

42. JEN understands that the AER does not intend to depart from long-standing regulatory practice in this respect, including for the reasons set out above. However if the AER was to change its practice and seek to rely on any information on actual debt costs in determining the return on debt allowance in the final decision, JEN would need to be informed of that, and provided with a reasonable opportunity to respond.[34]

1.4 UPDATE TO JEN RETURN ON DEBT AND INFLATION ESTIMATES

1.4.1 UPDATED ESTIMATE OF THE PREVAILING RETURN ON DEBT

43. As indicated in JEN's 6 January submission, the year one return on debt estimate included in that submission used a prevailing return on debt observation for 2016 that was based on a placeholder averaging period (20 business days to 30 September 2015). This was done because, at the time JEN was finalising its submission, data for JEN's actual averaging period was not yet available. JEN also explained that the prevailing return on debt observation for 2016 and the year one return on debt would be updated to reflect data for JEN's actual averaging period.[35]

44. Over the actual averaging period (15 business days to 4 December 2015), CEG produces an estimate of the prevailing return on debt of 5.65%, on a semi-annual basis. This is the sum of a 10-year swap rate of 3.02% and a debt risk premium (**DRP**) of 2.63%. The DRP estimate reflects CEG's best estimate of the prevailing DRP and is an equally weighted average of the DRP indicated by the BVAL, RBA and Reuters data sources (with the RBA curve extrapolated using the AER method). Further detail on the basis for this updated estimate is set out in the accompanying expert report from CEG.[36]

[32] AEMC, *Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 29 November 2012, p 43. The AEMC affirms that this statement remains apposite in respect of the final rule at pages 65 and 67.

[33] AEMC, *Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 29 November 2012, p 86.

[34] NEL, 16(1)(b).

[35] JEN, Revocation and substitution submission – Attachment 6-1 Rate of return, gamma, forecast inflation, and debt and equity raising costs, 6 January 2016, pp 34-36.

[36] CEG, *Best estimate of debt risk premium for the 16 November to 4 December 2015 period*, February 2016.

45. As in JEN's 6 January submission, this estimate is combined with estimates of the prevailing return on debt for the prior nine years to produce a placeholder estimate of the 10-year trailing average return on debt of 7.77%. This trailing average estimate is adopted by JEN as the best estimate of the return on debt for the first year of the 2016-20 regulatory control period.

Table 1–1: Updated calculation of trailing average return on debt for first year (%)

Year of data observation	10 year swap rate (base rate)	DRP	Return on debt	Basis for estimation
2006	6.077	0.643	6.720	Average of Bloomberg and RBA estimates over full calendar year
2007	6.639	0.941	7.580	
2008	6.659	2.972	9.631	
2009	5.591	3.946	9.537	
2010	5.872	2.780	8.652	
2011	5.505	2.828	8.333	
2012	4.165	3.084	7.249	
2013	4.238	2.841	7.080	
2014	4.011	2.059	6.069	
2015[1]	3.021	2.628	5.649	CEG best estimate of the prevailing DRP and yield, based on a simple average of the BVAL, Reuters, and RBA curves (with the RBA curve extrapolated using the AER method).
Simple average return on debt			**7.622**	
Annualised trailing average return on debt			**7.768**	

46. If a hybrid transition were adopted, this calculation would change as follows:

- The base rate would be re-estimated as the average of the 1 to 10 year swap rates, plus an allowance for swap transaction costs; and
- The return on debt for the first year would be re-estimated as a weighted average of the trailing average return on debt (7.62% in semi-annual terms) and the sum of the re-estimated base rate and the historical average DRP (5.11% in semi-annual terms), with weights to reflect the portion of the return on debt that was assumed to be hedged under the on-the-day approach.

47. As noted in JEN's 6 January submission, empirical analysis by CEG demonstrates a hedging ratio of approximately one third would have minimised interest rate risk under the on-the-day approach.[37] This implies that if the hybrid transition were adopted, the return on debt for the first year of the regulatory period would be 6.90% (once converted to annual terms).[38]

37 CEG, *Efficient Use of Interest Rate Swaps to Manage Interest Rate Risk*, June 2015; CEG, *Critique of the AER's approach to transition*, December 2015, section 5.

38 This is calculated by applying two thirds weight to the trailing average return on debt (7.77%) and one third weight to the sum of the re-estimated base rate and the historical average DRP (5.17%).

1.4.2 UPDATED INFLATION FORECAST

48. JEN relied on the same placeholder averaging period for the purposing of forecasting inflation in its 6 January submission.[39]

49. JEN has now updated its forecast of inflation based on its actual averaging period, using the same method as JEN relied on its 6 January submission (i.e. the Fisher equation method, with neither of the further adjustments recommended by CEG, both of which have the effect of lowering the inflation forecast). This results in a conservative estimate of forecast inflation over the 2016-20 regulatory control period of 2.25%.[40]

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[39] JEN, Revocation and substitution submission – Attachment 6-1 Rate of return, gamma, forecast inflation, and debt and equity raising costs, 6 January 2016, Table 5-2.

[40] CEG, *Best estimate of debt risk premium for the 16 November to 4 December 2015 period*, February 2016, Appendix B.3.

2. DEMAND MANAGEMENT INCENTIVE ALLOWANCE

2.1 NAGA AND EAGO SUBMISSION

50. In their submission, NAGA and EAGO note that:

> *On average, allowances under the scheme equate to just 0.09% of the total revenue allowances for each DNSP. This amount is clearly insignificant when compared with other industrialised businesses where expenditure on research and development is often higher by several orders of magnitude*[41]

2.2 JEN'S RESPONSE

51. JEN is a strong advocate of demand management. In the previous regulatory period, we have spent the highest proportion of approved DMIA of any distribution company in the NEM.[42] We have also provided a robust and well justified DMEGCIS program for the 2016-20 regulatory control period[43] including significant justification as to why the Preliminary Decision DMIA allowance of $1m is insufficient.[44]

52. Consistent with the sentiment of NAGA and EAGA we believe the DMIA in the AER's Preliminary Decision is insufficient. There is very substantial innovation and political will promoting demand management solutions over the 2016-20 regulatory control period. Providing for expenditure of only $1m in this context is therefore at odds with the market environment/public policy.

53. Approving a DMIA of $5.6m is recognition of the consumer benefit that derives from investment in demand management activities which is reflective of the National Electricity Objective (**NEO**).

41 NAGA and EAGO, "Victorian Electricity Distribution Price Review 2016-20 Preliminary Decision October 2015", 6 January 2016, p. 2.

42 AER, "Decision, Applications by DNSPs for Demand Management Innovation Allowance for: - 2013 calendar year (Victorian DNSPs); and - 2012–13 financial year (all other DNSPs)", April 2015.

43 JEN, "2016-20 Electricity Distribution Price Review, Regulatory Proposal, Attachment 5-5, Innovation and Technology Investment", 30 April 2015.

44 JEN, "2016-20 Electricity Distribution Price Review Regulatory Proposal, Revocation and substitution submission, Attachment 3-1 Incentive schemes", 6 January 2016, pp. 23-27.

3. BENEFITS REALISATION THROUGH THE AMI ROLL-OUT

3.1 MINISTER'S SUBMISSION

54. The Minister's submission proposes efficiency gains derived from the AMI rollout program should be passed onto customers in the form of a lower revenue allowance for the Victorian distribution network service providers.

55. The Minister's submission refers to the Minister's earlier submission[45] (**Minister's July submission**) in which it cites a decision of Office of Gas and Electricity Markets (**Ofgem**) (**Ofgem determination**) to pass on cost savings attributed to smart grids benefits (**SGB**):

> *Given the level of investment consumers have made in innovation projects and the smart metering programme, we would expect savings from these to be on top of historical levels of ongoing efficiency.*
>
> *... The adjustment for smart grids and other innovation, represents, on average, an additional frontier shift of 0.2% per year for slow track DNOs. The total smart savings (embedded and additional) are 0.6% per year, compared to the DNOs' ongoing efficiency assumptions of between 0.8 and 1.1% per year*[46]

56. In the Minister's July submission the Minister claims that a similar adjustment should be made to the revenue allowances of the Victorian distribution businesses.

57. The Minister's submission also notes that the AER's Preliminary Decision rejects applying the Ofgem approach—as sought in the Minister's July submission—on the basis that:

- the benefits had been largely realised and that the benefits have been captured in the base year, and
- the Department of Economic Development, Jobs, Transport and Resources (**DEDJTR**) did not identify or quantify the value of the benefits.

58. In response, the Minister's submission directs the AER to the "Advanced metering infrastructure cost benefit analysis"[47] report (**CBA report**) to identify and quantify the benefits of rolling out smart meters.

3.2 JEN'S RESPONSE

3.2.1 OFGEM'S DECISION FOR COST SAVINGS

59. Ofgem's determination for reducing regulatory allowances for SGB was taken to appeal by Northern Powergrid Group (**NPg**).[48] The Competition and Markets Authority (**CMA**)—hearing the appeal—considered Ofgem[49] had

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[45] Victorian Department of Economic Development, Jobs, Transport & Resources, "Submission to Victorian electricity distribution pricing review – 2016 to 2020", [undated].

[46] Ofgem, "RIIO-ED1: Final determinations for the slow-track electricity distribution companies; Overview; Final Decision", 28 November 2014, para 4.70.

[47] Deloitte, "Advanced metering infrastructure cost benefit analysis", 2 August 2011.

[48] Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc

[49] Ofgem supports the Gas and Electricity Markets Authority (**GEMA**) which is the government regulator for the electricity and downstream natural gas markets in Great Britain.

made an error in making the adjustment to revenue allowances and therefore rejected the decision made by Ofgem as follows:

> *"We therefore determine that the SGB adjustment that GEMA applied to NPg was not justified and that GEMA's decision was wrong because of an error of law and/or an error of fact. Accordingly, we uphold NPg's appeal."*[50]

60. In rejecting Ofgem's approach CMA also made a number of other observations including:

> *"In our view, the importance of smart grid technology is not, in itself, justification for decreasing NPg's revenue allowance and departing from the approach set out at the Strategy Decision stage which involved SGBs being assessed as part of GEMA's general cost benchmarking exercise. …Therefore, we consider that the basis for GEMA's change of approach and its judgement that potential SGBs had been underestimated requires careful consideration."*[51]

> "*Taking all the evidence in the round, we are not satisfied that the estimate of smart metering savings in the DECC Impact Assessment can be relied on, to the extent that GEMA continued to do so, to support the view that the identified level of embedded SGBs at Final Determinations was likely to be insufficient*."[52]

> *"We are not persuaded that GEMA's assessment of external evidence, or its quantitative assessment of DNO business plans presented at Final Determinations provided material support for its view that there was a likely SGB shortfall that justified an adjustment."*[53]

61. Far from the Ofgem decision supporting any reduction in allowed revenues (as proposed by the Minister), the decision on appeal is clear evidence of the error of this proposed approach.

62. We also consider that CMA's decision highlights potential issues which can arise in relying upon expert reports (such as the DECC Impact Assessment in the NPg case and the Deloitte report in the case of the Victorian DNSPs) as the basis for making efficiency adjustments. It is apparent that Ofgem also noted the limitations of utilising such reports as, following criticism by the UK DNOs of the reports and the risks of relying upon them, Ofgem changed its approach between the draft decision (where it relied upon the report) and its final determination (where much less reliance was placed on these reports). We consider there are similar risks and issues with the CBA report which would make reliance on the report inappropriate (see section 3.2.2 below).

3.2.2 RESPONSE TO THE MINISTER'S SUBMISSION

63. The Minister's submission confirms that some of the benefits identified in the CBA report have already been included in the distribution determinations.[54] Accordingly if the CBA report was adopted in the manner suggested by the Minister's submission there would be a risk of error arising from double counting of benefits.

64. Further, whilst the CBA report provides useful input into the benefits from AMI meters to Victorian electricity users at the time it was developed; it cannot be relied upon for making adjustments to the revenue requirement of JEN for the 2016-20 regulatory control period for the following reasons:

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50 CMA, "Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc v the Gas and Electricity Markets Authority, Final determination", 29 September 2015

51 Ibid, p 46, para 4.53

52 Ibid, p 56, para 4.82

53 Ibid, p 66, para 4.119

54 Victorian Government, "Submission on the Victorian electricity distribution network service providers' preliminary distribution determinations for 2016-20", [undated], p.2.

- The CBA report was released five years ago, it does not reflect more recent legislative, regulatory and market developments which underpin the cost / benefit analysis. The CBA report itself encountered changes in the regulatory framework stating “adjustments need to be made on both sides of the cost-benefit equation”[55] when compared to previous cost benefit analysis of the AMI program.

  In the recent rule change on expanding competition in metering and related services[56] the AEMC established a framework for distribution businesses to acquire data and services from metering coordinators on a commercially negotiated basis.[57] This new operating model supersedes the framework present at the time of the development of the CBA report which assumed distribution businesses could access the data and services from its own meters.[58] As distribution businesses will incur additional costs for data and services necessary to realise the benefits in the items outlined in the Minister’s submission the benefits identified in the CBA report are not correct and cannot be reasonably relied upon.[59]

  Additionally, the Value of Customer Reliability (**VCR**) used in the CBA report[60] stem from AEMO’s 2008 VCR report, these are out of date given AEMO has released a more recent set of VCR values.[61] Given this difference it would be inappropriate to rely on the CBA report because (i) the extent of benefits no longer reflect the value customers place on them, (ii) is not consistent with the VCR adopted in JEN’s overall proposal and (iii) is inconsistent with the VCR adopted in the Preliminary Decision.

- The CBA report does not provide sufficient detail on the benefits to accurately apply adjustments in the decisions of the Victorian distribution businesses.
  - The CBA report forecasts costs across Victoria, however the Minister’s submission does not allocate the benefits to each of the Victorian distribution businesses; nor does it offer a process for doing so.
  - The CBA report does not identify the timing of the benefits. As noted in the Minister’s submission, the CBA report covers twenty years, however, this report does not identify how much, if any, is attributed to the 2016-20 regulatory control period.
- Initiatives may require additional investment over and above the AMI investment—to realise the benefits of the AMI program (see the comment above regarding the rule change on metering competition). JEN has not required specific allowances for the initiatives identified in the other matters list provided in the Minister’s submission.
- Some of the benefits are already captured in the operating expenditure base year and capital expenditure forecast, for example:
  - Customer benefit of being able to switch retailer more quickly and more certainly; and
  - Avoided costs of installing import/export metering.
- The CBA report itself also identifies numerous areas of risk, or issues which could impact the legitimacy of its findings. The issues identified include:

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55 Deloitte, “Advanced metering infrastructure cost benefit analysis”, 2 August 2011, p. 42.

56 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.

57 Ibid, section A5.

58 Advanced Metering Infrastructure Order in Council made by the Governor of Victoria under section 15A and section 46D of the Electricity Industry Act 2000 (Vic) and published in the Victoria Government Gazette on 28 August 2007, including amendments up to 30 July 2015.

59 On this point JEN considers that Meter Coordinators (**MC**) will offer service and data just below the cost of the benefit, in this circumstance there will not be any benefit to the network for such services as purported in the CBA report.

60 Deloitte, “Advanced metering infrastructure cost benefit analysis”, 2 August 2011, p. 61.

61 AEMO, “Value of customer reliability review, final report” September 2014.

- Removal of the AMI mandate which could significantly reduce the net benefits.[62]
- No inclusion in the report of analysis or allowance for the costs of customer's refusal to accept smart meters and the resulting impacts of such refusal to lower smart meter benefits.[63,64]
- No consideration in the report of the risks of effective deployment and utilisation of AMI technology and lack of effective customer engagement.[65]
- No incorporation in the analysis of the costs of the customer engagement program.[66]
- No incorporation of the AER's actual decisions on allowances for the 2012-2015 period but instead utilising adjustments to reflect Deloitte's view of the likely costs that will be approved by the AER.[67]
- The costs estimates used in the CBA report are subject to some uncertainty with regard to implementation of the technology and costs could vary from those assumed in the CBA report.[68]
- The CBA report notes the differences between the DNSPs in terms of the communications technologies adopted and the back office IT systems[69] but does not identify how this may affect the benefits to those DNSPs.
- The CBA report notes that many of the benefits identified in the CBA report will require regulatory changes and depend upon customer response to electricity prices and other incentives.[70]
- The CBA report does not incorporate risks of cost increases including performance costs, regulatory incentive risk, costs of customers rejecting the technology.[71]
- The CBA report does not incorporate the cost of problems in enabling AMI communication systems.[72]
- The CBA report could not estimate the base case customer service cost for JEN and accordingly assumed an average customer service costs for JEN.[73]

65. Given these issues it is not possible to rely on the CBA report to inform adjustments to the revenue required of the Victorian distribution businesses.

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62 Deloitte, "Advanced metering infrastructure cost benefit analysis", 2 August 2011, p. 5 and 10

63 Ibid, p. 8

64 Over the period of time in which the CBA report was developed, and soon after its release, JEN experienced an increase in the number of refusals and incurred additional costs managing the consequences; this was outlined to the AER in our 2015 charges application (see JEN, "AMI Charges Revision Application for CY2015", 29 August, 2014, Section 1.5). The realisation of this risk demonstrates the deficiencies in the cost benefit analysis identified in the CBA report.

65 Deloitte, "Advanced metering infrastructure cost benefit analysis", 2 August 2011, p. 9

66 Ibid, p.9, footnote 4

67 Ibid, p. 10

68 Ibid, p. 11

69 Ibid, p. 9

70 Ibid, p. 14

71 Ibid, p. 17

72 Ibid, p. 37

73 Ibid, p. 43

4. CUSTOMER CONTRIBUTIONS FOR NEW CONNECTIONS

4.1 MINISTER'S SUBMISSION

66. The Minister's submission notes that:[74]

> *The customer contributions for new connections that have been accepted by the AER are based on the Essential Service Commission's Electricity Guideline No. 14: Provision of Services by Electricity Distributors (Guideline 14). Guideline 14 states that the incremental revenue for a new connection is calculated assuming that the X-factor in the final year of the current regulatory control period applies in subsequent years.*

67. And that: [75]

> *Guideline 14 states that the incremental revenue for a new connection is calculated assuming that the X-factor in the final year of the current regulatory control period applies in subsequent years.*

68. The Minister's submission also states that the x-factor in the final year will impact the calculation of connection costs.

69. Finally, the Minister's submission notes that the intention of the Victorian Government to transition towards using the connection process under Chapter 5A of the NER and that this will have implications on customer contribution revenues.

4.2 JEN'S RESPONSE

70. JEN agrees with the Minister's submission that customer contribution forecast need to be amended to reflect the transition to NER chapter 5A approach to connecting customers; in our recent Revocation and Substitution Submission[76] we incorporated these changes. We also proposed a further operating expenditure step change to fulfil the new requirements.[77]

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74 Minister's submission, p. 5.

75 Minister's submission, p. 5.

76 JEN, "2016-20 Electricity Distribution Price Review Regulatory Proposal, Revocation and substitution submission, Attachment 7-1 Capital expenditure", 6 January 2016, p. 25.

77 JEN, "2016-20 Electricity Distribution Price Review Regulatory Proposal, Revocation and substitution submission, Attachment 8-2 Operating expenditure step changes", 6 January 2016, pp. 76-79.

5. VEGETATION MANAGEMENT

5.1 MINISTER'S SUBMISSION

71. The Minister's submission states: [78]

> *the AER should be assessing a negative step change in operating expenditure for each of the DNSPs, not just those that proposed a positive step change.*

72. The Minister's submission claims the increase in costs caused by the introduction of new electricity line clearance obligations in 2015 are offset by the reduction in costs associated by the changes in obligations that were introduced in 2010. The Minister concludes that no positive operating expenditure step change should be permitted in the 2016-20 regulatory control period because of this offset.

73. The Minister's submission does not provide any additional evidence to support the submission that the regulatory changes are likely to lower costs.

5.2 JEN'S RESPONSE

74. JEN notes that the Minister's submission on this issue is directed towards the Ausnet, Powercor and United Energy networks, however, for the avoidance of doubt, JEN has demonstrated in its Revocation and Substitution Submission[79] that based on the views of the ESV and vegetation management experts, the re-introduction of exceptions for the maintenance of structural branches will not result in any cost savings for JEN and therefore should not be considered as an offset for the clear cost increases arising from the introduction of the other new obligations under the 2015 Regulations.

75. Moreover, the Minister's submission suggests that the cost of compliance should be reassessed (and lowered through a step change) once the ESV issues guidance notes in relation to its approach to administration. For the reasons set out our Revocation and Substitution Submission – and supported by advice from counsel – the administrative approach of the ESV does not modify or reduce the legal obligations or standard which JEN and other DSNPs are required to meet in order to comply with the 2015 Regulations.

[78] Minister's submission, pp. 6-9.

[79] JEN, "2016-20 Electricity Distribution Price Review Regulatory Proposal, Revocation and substitution submission, Attachment 8-2 Operating expenditure step changes", 6 January 2016, section 5.3.7

6. GUARANTEED SERVICE LEVEL PAYMENTS

6.1 MINISTER'S SUBMISSION

76. The Minister's submission states: [80]

> *the ESC proposed a number of changes to the Victorian GSL payments scheme* [81]

77. and that:[82]

> *In its final distribution determination, the AER will need to take into consideration the outcomes of this review in the forecast operating expenditure for the DNSPs.*

6.2 JEN'S RESPONSE

78. At the time of developing our Revocation and Substitution Submission we became aware of the ESC's intention to amend the GSL obligations through the release of a draft decision in November 2015. We have incorporated these changes into our Revocation and Substitution Submission by seeking a further operating expenditure step change.[83]

[80] Minister's submission, p. 8.

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

[82] Minister's submission, p. 8.

[83] JEN, "2016-20 Electricity Distribution Price Review Regulatory Proposal, Revocation and substitution submission, Attachment 8-2 Operating expenditure step changes", 6 January 2016, pp. 68-72.

7. REFCL IMPACTS ON STPIS TARGETS

7.1 MINISTER'S SUBMISSION

79. The Minister's submission states: [84]

> *The AER has accepted a couple of expenditure proposals that would be expected to result in a material improvement in supply reliability, but has not made any modifications to the DNSP's performance targets for the 2016-20 regulatory control period.*

80. It also cites a study by Northpower in New Zealand[85] indicating: [86]

> *91% of all earth-faults were compensated successfully ... and they saw a 61% improvement in SAIDI*

81. The Minister's submission cites the AER's decision to approve JEN's expenditure on REFCL devices on the grounds of safety and reliability

7.2 JEN'S RESPONSE

82. Whilst the STPIS permits the AER to amend targets in certain circumstances,[87] these circumstances do not occur with the roll out of REFCL devices. Section 3.2.1(a)(1A) of the STPIS[88] outlines the following criteria for amending the performance targets where reliability improvements are planned:

- Reliability improvements are planned in the regulatory proposal, or
- Cost of improvements is approved in the previous regulatory period, and
- There is expected to be a material improvement in supply reliability.

83. We discuss each of these criteria below.

7.2.1 RELIABILITY IMPROVEMENTS ARE NOT PLANNED IN THE REGULATORY PROPOSAL

84. JEN does not plan to improve reliability due to the installation of REFCL devices during the 2016-20 regulatory control period.

85. The primary driver for REFCL installation is to reduce the risk of bushfire ignition by electricity assets. It does have potential reliability benefits as faults triggered by transient faults could self-clear and not result in supply interruptions. There are however a number of factors to consider:

[84] Minister's submission, p. 8.

[85] Rao, Mengyun, Assessing Ground Fault Neutraliser (**GFN**) deployment and benefits in 11kV Electricity Network – Power Systems Group, University in Auckland quoted in Keen, Dennis and Macdonald, Steve, Darsfield to Dunsandel and Beyond – The Development of the Ground Fault Neutralizer in New Zealand and Lessons Learned, EEA Conference & Exhibition 2013, 19-21 June, Auckland

[86] Minister's submission, p. 8.

[87] AER, "Electricity distribution network service providers Service target performance incentive scheme", November 2009, section 3.2.1.

[88] AER, "Electricity distribution network service providers Service target performance incentive scheme", November 2009.

- operating Mode – JEN does not intend to place the REFCL in full service except on high bushfire risk days. On other days REFCL will be in service but will be switched off when the fault lasts longer than a pre-determined time (approximately 5 seconds), for reasons outlined below. This operating mode is chosen after careful consideration of public health and safety and reliability impact resulting from the REFCL installation. This means that the REFCL's influence on reliability performance will be negligible as it will be in full service only a few days in a year.

  Extensive risk assessment carried out as part of the REFCL design has resulted in JEN's decision to have the REFCLs in full service only during high bushfire risk days, to reduce its negative impact on supply reliability.

- transient fault (Momentary Average Interruption Frequency Index (**MAIFI**)) performance – With the above operating mode, REFCL can potentially improve JEN's MAIFI performance. However, MAIFI is a small component of the overall STPIS incentive mechanism. With REFCL installations in 4 out of the 27 zone substations at the end of 2020, the potential for improvement is insignificant. In addition, there is an offsetting factor for reliability as explained below.
- impact on existing equipment – Over recent regulatory control periods JEN has installed devices that assist in sectionalising its HV distribution feeders to reduce the number of customers affected by a single fault event, as a strategy to maintain supply reliability in an environment of increasing asset failures (caused by asset ageing) and deteriorating weather pattern. These devices consist of pole-mounted automatic circuit re-closers, load break switches, fault passage indicators and spur fuses. These devices will not work satisfactorily when the REFCL is in service due to the much reduced ground fault current. This means that a permanent fault will cause the whole feeder to go out of service, instead of part of the feeder only, resulting in deterioration in reliability performance.

  In addition, the operation of the REFCL requires longer time duration to allow for self-clearing of transient fault and fault detection. This longer time duration will place voltage stress on distribution assets on the healthy part of the distribution feeder, increasing the possibility of cascaded asset failures.

86. The Minister's comparison with reliability improvement achieved by Northpower in New Zealand is not appropriate as it does not evidence any comparability to the operating environment or purpose for which the devices are used. There is little context on the 61% reliability improvement experience by Northpower, for example, is this improvement based on a single feed or across the network and if it is the latter is it by feeder classification? In the absence of robust material that can be understood and tested by the AER and stakeholders, this cannot be relied upon to produce a reasonable or reliable adjustment to STPIS targets.

7.2.2 COST OF IMPROVEMENTS IS APPROVED IN THE PREVIOUS REGULATORY PERIOD

87. Expenditure on Ground Fault Neutralisers (**GFN**), (a form of REFCL device) was approved for installation in three JEN zone substations by the AER in the 2011-15 regulatory period.[89] The expenditure was justified on the basis of public health and safety considerations, including mitigation against fire start, step and touch potential and flash burn to live line workers, and not on reliability improvement. However, the installation of the devices was put on hold pending the outcome of the Powerline Bushfire Safety Taskforce[90] investigation and test results, meaning there has not been any reliability improvement expenditure in the previous regulatory control period.

89 AER, "Final decision, Victorian electricity distribution network service providers, Distribution determination 2011–2015", October 2010.

90 The Powerline Bushfire Safety Taskforce (**PBST**) was established in August 2010 to recommend to the Victorian Government how to maximise the value to Victorians from the Victorian Bushfire Royal Commission recommendations. The PBST provided its final recommendation to the Victorian Government on 30 September 2011. The Victorian Government accepted PBST's recommendations and in December 2011 announced a package of initiatives. Among these initiatives was the rollout of REFCLs in zone substations prone to bushfire start risk.

7.2.3 THERE IS EXPECTED TO BE A MATERIAL IMPROVEMENT IN SUPPLY RELIABILITY

88. JEN does not anticipate a material improvement in supply reliability, in fact, per section 7.2.1, JEN envisages a possibility that reliability may deteriorate rather than improve as a result of the deployment of REFCL devices in the JEN electricity distribution network.

89. Irrespective of the possibility of degradation of performance, the impacts on STPIS for JEN are expected to be immaterial. To determine an adjustment to the STPIS target the following factors will need to be taken into account:

- REFCLs will only operate in full service a small number of days of the year
- JEN only contemplates installing 4 REFCL devices over the 2016-20 regulatory control period, affecting only a small proportion of assets (this is a low proportion as contemplated by the Powerline Bushfire Safety Taskforce)
- most REFCL devices are expected to be installed late in the 2016-20 regulatory control period
- the devices will be installed in rural areas which only cover three percent of JEN's customers—as STPIS is calculated based on average performance across the customer base the impact is diluted significantly.

90. These factors, considered together, means the impacts on targets will be immaterial.

7.2.4 CONCLUSION

91. For the reasons above, none of the arguments provided by the Minister provide any justification for adjusting STPIS targets in the 2016-20 regulatory control period.

8. COST ALLOCATION BETWEEN STANDARD CONTROL AND METERING SERVICES

8.1 MINSITER'S SUBMISSION

92. The Minister's submission stresses the importance getting the allocation of costs right between metering services and SCS noting:[91]

> *if the allocation of costs between standard control services and metering services is not resolved as part of this distribution determination, the risk of consumers paying twice will increase.*

8.2 JEN'S RESPONSE

93. JEN does not agree with the Minister's submission claim that the risk of paying twice increases. JEN must report its costs using an AER approved cost allocation method (**CAM**) and must also report costs under a Regulatory Information Notice (**RIN**) (those reports being subject to audit by reputable accounting firms). Through these mechanisms our customers can be sure that JEN does not double count its costs and therefore cannot recover its costs twice—as the CAM only allocates a cost to a service and category once. The question being considered during the current EDPR is whether some costs are better treated as relating to standard control services or the metering alternative control service.

94. JEN agrees that it is important to get the allocations right. To this end JEN notes it has implemented the recommended cost allocation between metering and SCS services in its response to the AER's revocation and substitution process and identifies sound economic rationale in the context of the legislative and NER requirements.

95. JEN agrees with the Minister's submission statement that the method employed by the AER to allocate costs between SCS and metering services would mean "metering charges for small customers will therefore be higher than they would otherwise"[92] and to resolve this inefficient outcome the cost allocations proposed by JEN[93] between metering services and SCS should be adopted in the substitute determination.

[91] Minister's submission, p. 9.

[92] Minister's submission, p. 10.

[93] JEN, Revocation and substitution submission – Attachment 9-1 Alternative control metering services, 6 January 2016, pp 44-45

9. CONCLUDING REMARKS

96. If the AER has any questions or concerns regarding this submission, or otherwise, or if there is a material issue under consideration by the AER in respect of this or other stakeholder submissions (or in respect of any other matter of which we have not been informed), which the AER considers may materially alter its position in a manner adverse to JEN, we request a reasonable opportunity to understand and provide further information before the AER makes its substitute decision.

Appendix A
Attachments to this submission

Jemena

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A1. LIST OF ATTACHMENTS TO THIS SUBMISSION

97. The list of attachments to this submission are listed in Table A1–1.

Table A1–1: Attachments to this submission

Ref	Attachment
1	CEG , *Best estimate of debt risk premium for the 16 November to 4 December 2015 period*, February 2016
2	Frontier Economics, *Response to submissions on the relevance of the TransGrid sale*, February 2016

98. The list of models—updated relative to our 6 January 2016 submission—are outlined in Table A1–2.[94]

Table A1–2: Updated models attached to this submission

Ref	Model	Change
3	Rate of Return Model - Attachment 06.02 - JEN SCS Distribution - Rate of Return Model (PUBLIC)	• Updated inflation assumptions for the 16 November to 4 December 2015 averaging period; and • Updated cost of debt assumptions (bond yields) for the 16 November to 4 December 2015 averaging period.
4	Distribution RAB Roll Forward Model - Attachment 05.03 - JEN SCS Distribution - RAB RFM (PUBLIC)	• Updated CY15 gross capex, capital contributions and disposals by RAB asset class; and • Updated CY15 gross capex by TAB asset class (Group 3).
5	Distribution PTRM Model - Attachment 05.02 - JEN SCS Distribution - PTRM (CONFID) and Attachment 05.02 - JEN SCS Distribution - PTRM (PUBLIC)	• Updated the DMIS assumptions within revenue adjustments as per Attachment 05-05 • Refreshed from ref 3 and 4
6	Opex Models – Attachment 08.03 - JEN SCS Distribution - Opex Forecast Model (PUBLIC) and Attachment 09.04 - JEN ACS Metering - Opex Forecast Model (PUBLIC)	• Added a section to drive the splits by activity type between ACS and SCS
7	Metering PTRM Model - Attachment 09.04 - JEN ACS Metering - Opex Forecast Model (PUBLIC)	• Refreshed links to capture changes within the Rate of Return Model • Refreshed from ref 3

94 Model changes also incorporate the impacts of responses to the AER's questions received on JEN's revocation and substitution submission, namely #IR028, #IR30 and #IR031.