Response to the Regulatory Information Notice

Under Division 4 of Part 3 of the National Electricity (New South Wales) Law

April 2018

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General requirements

1. Provide information

RIN section	Requirement	Essential Energy Response
1.1	Provide the information required in each regulatory template in the Microsoft Excel Workbooks attached at Appendix A, completed in accordance with:	The information required in the regulatory templates has been provided in accordance with this notice, the instructions in Appendix A, the instructions in Appendix E, the service classifications set out in the Framework and Approach paper, and Essential Energy's cost allocation method which can be found at attachment 11.1 of our Regulatory Proposal. The completed Regulatory Templates are provided as Attachments R1a, R1b, R1c and R1d to this RIN Response.
1.1 (a)	this *notice;*	
1.1 (b)	*the instructions in the relevant Microsoft Excel Workbooks attached at Appendix A;*	
1.1 (c)	the instructions in Appendix E; and	
1.1 (d)	the service classifications set out in the *framework and approach paper*; and	
1.1 (e)	Essential Energy's approved *cost allocation method.*	
1.2	If: (a) Essential Energy's cost allocation method has changed during the current regulatory control period, or (b) Essential Energy service classification have changed from the current regulatory control period, or (c) Essential Energy proposes to divert from the service classification set out in the relevant framework and approach paper, or (d) Essential Energy proposes to change its cost allocation method for the forthcoming regulatory control period; such that there would be material changes to information previously submitted to the AER Essential Energy must use the regulatory templates in Workbook 3 – Recast category analysis and Workbook 4 – Recast economic benchmarking attached at Appendix A to submit revised historical information.	Essential Energy changed its cost allocation method during the current regulatory control period. As directed by the AER, back-casting of information for our Alternative Control Services was completed as part of the FY17 annual RIN process. The AER advised back-casting of Standard Control Services was not required. Therefore, no back-casting for this change has been included in the Reset RIN package. There are no material changes to information previously supplied due to service classifications that have changed from the current regulatory period and Essential Energy has not proposed diverting from the service classifications in the relevant Framework and Approach paper.

RIN section	Requirement	Essential Energy Response
1.3	For all information, other than forecast information, provide in accordance with this notice and the instructions in Appendix E, a basis of preparation demonstrating how Essential Energy has complied with this notice in respect of:	A Basis of Preparation has been provided as Attachment R2 to this RIN response. This documents Essential Energy's compliance with the notice when completing the regulatory templates.
1.3 (a)	the information in each regulatory template in the Microsoft Excel Workbooks attached at Appendix A; and	
1.3 (b)	the information prepared in accordance with the following requirements in Schedule 1 of this notice; (i) paragraph 1.2 (ii) paragraph 5.1 (a)(ii) (iii) paragraph 8.5 (iv) paragraph 13 (13.5 and 13.6) (v) paragraph 15 (15.2 and 15.3) (vi) paragraph 16 (16.2 - 16.7, 16.10)	
1.4	Provide material used for the purposes of preparing the *regulatory proposal*:	Note only
1.4 (a)	all consultants' reports commissioned and relied upon in whole or in part	Consultant reports relied upon in preparing our 2019-24 regulatory proposal and attached to the regulatory proposal include: > Attachment 4.3 - Engagement Programme Summary Report Phase 1 (Woolcott) > Attachment 4.4 - Engagement Programme Summary Report Phase 2 (Woolcott) > Attachment 4.5 – Pricing Working Group Engagement Report (FarrierSwier) > Attachment 4.6 – Closing the Loop Report Phase 3 Engagement (Woolcott) > Attachment 4.8 - Business Survey Findings Report Phase 1 (Woolcott) > Attachment 4.9 – Business Survey Findings Report Phase 2 (Wolcott) > Attachment 4.10 – Essential Energy Community Forum Report Phase 1 (Woolcott) > Attachment 4.11 – Essential Energy Community Forum Report Phase 2 (Woolcott) > Attachment 4.12 – Residential Consumer Findings Report Phase 1 (Woolcott) > Attachment 4.13 – Residential Consumer Findings Report Phase 2 (Woolcott) > Attachment 13.1 – Assessment of Operating Environment Factors (Frontier Economics) > Attachment 13.2 – Economic benchmarking analysis (Frontier Economics) > Attachment 14.1 – Electrical energy and customer number projections for Essential Energy in New South Wales to 2029-30 (National Institute of Economic and Industry Research) > Attachment 15.1 – rate of return (Competition Economists Group)

RIN section	Requirement	Essential Energy Response
		The following consultant reports are provided as supporting documents to our 2019-24 regulatory proposal: > Supporting document 9.2.1 – Labour escalation factors affecting expenditure forecasts (Competition Economists Group) > Supporting document 11.3.1 – Analysis of Essential Energy's expenditure variations over the 2014-19 regulatory control period (Synergies) > Supporting document 12.1.2 - Risk versus expenditure (CutlerMerz)
1.4 (b)	all material assumptions relied upon	Attachment 11.2 (Key Assumptions) to our Regulatory Proposal details are material assumptions relied upon.
1.4 (c)	a table that references each response to a paragraph in this Schedule 1 and where it is provided in or as part of the regulatory proposal	This document - (Essential Energy Response to RIN Schedule 1) provides a response to each paragraph.
1.4 (d)	a table that references each document provided in or as part of the regulatory proposal and its relationship to other documents provided; and	Refer to Attachment R3 to this RIN response – Regulatory Proposal Documentation List. This attachment provides a full list of supporting documents to our 2019-24 regulatory proposal and tariff structure statement.
1.4 (e)	each document identified in paragraph 1.4(d) must be given a meaningful filename in the form: Essential Energy – [Author] – [title] – [date] – [public/confidential], where:	
1.4 (e) i	Author is the author of the file if not Essential Energy, for example a consultant or other third party;	
1.4 (e) iii	Title provides a meaningful description of the content of document, with limited reliance on acronyms or cross references, for example "Appendix 1A" is not meaningful, but "Appendix 1A – Cost allocation method" is;	
1.4 (e) iii	Date is a relevant date associated with the file, generally the date the document was created	
1.4 (e) iv	Public/confidential identifies if the file in its entirety can be published (public); or if it contains any information which is the subject of a claim for confidentiality in accordance with paragraph 33 of this notice (confidential).	
1.5	Provide for each material assumption identified in the response to paragraph 1.4(b):	Refer to Attachment 11.2 (Key Assumptions) to the Regulatory Proposal for all details relating to key material assumptions which comply with clause 1.5 (a) through to 1.5 (d) (ii).
1.5 (a)	its source or basis;	

RIN section	Requirement	Essential Energy Response
1.5 (b)	if applicable, its quantum;	
1.5 (c)	whether and how the assumption has been applied and was taken into account; and	
1.5 (d)	the effect or impact of the assumption on the capital and operating expenditure forecasts in the forthcoming regulatory control period taking into account:	
1.5 (d) i	the actual expenditure incurred during the current regulatory control period; and	
1.5 (d) ii	the sensitivity of the forecast expenditure to the assumption.	
1.6	Provide reconciliation of the capital and operating expenditure forecasts provided in the regulatory templates to the proposed capital and operating allowances in the post tax revenue model for the forthcoming regulatory control period.	Refer to Attachment R4 to this RIN response – Reconciliation of regulatory templates. This attachment provides a full reconciliation of the capital and operating expenditure forecasts provided in the regulatory templates to the proposed capital and operating allowances in the post tax revenue model for the 2019-24 regulatory period.
1.7	Where the regulatory proposal varies or departs from the application of any component or parameter of the capital efficiency sharing scheme, efficiency benefit sharing scheme, demand management incentive scheme or service target performance incentive scheme as set out in the framework and approach paper, for each variation or departure explain:	Essential Energy is not proposing any departures from any of these schemes. Further details can be found in the Framework and Approach chapter to our Regulatory Proposal.
1.7 (a)	the reasons for the variation or departure, including why it is appropriate;	
1.7 (b)	how the variation or departure aligns with the objectives of the relevant scheme; and	
1.7 (c)	how the proposed variation or departure will impact the operation of the relevant scheme	

2. Classification of services

RIN section	Requirement	Essential Energy Response
2.1	Identify each proposed service classification in the regulatory proposal which departs from a service classification set out in the framework and approach paper and explain:	Refer to Attachment 8.1 (Classification of Services) to our Regulatory Proposal
2.1 (a)	the reasons for the departure, including why the proposed service classification is more appropriate; and	
2.1 (b)	how service will differ under the proposed service classification in comparison to that in the framework and approach paper.	
2.2	If the proposed service classifications in the *regulatory proposal* depart from any of the service classifications set out in the *framework and approach paper:*	Essential Energy has not completed a second set of regulatory templates, as proposed changes are immaterial and driven by ring-fencing. The only proposed changes to the Classification of Services table are to: > Include new services related to Essential Energy being allowed to act as a Provider of Last Resort. > Allow us to recover costs from specific customers for NER Chapter 5 large-scale connections for notionally contestable works that are deemed non-contestable (largely due to safety, reliability or security of supply reasons). This will shift some services from Unclassified to Ancillary Network Services (ANS). The new services have been included in the ANS models and the submitted RIN templates for ANS. There is no impact on Standard Control Services. Refer to Attachment 8.1 (Classification of Services) to the Regulatory Proposal for details on departures from the final Framework and Approach Classification of Services table.

3. Control mechanisms

RIN section	Requirement	Essential Energy Response
3.1	For the forecast revenues that Essential Energy proposes to recover from providing *direct control services* over the *forthcoming regulatory control period* provide:	Refer to Attachment 16.2 (Control Mechanisms) to the Regulatory Proposal.
3.1 (a)	formulaic expressions for the basis of control mechanisms for standard control services and for alternative control services*;* and	
3.1 (b)	a detailed explanation and justification for each component that makes up the formulaic expression.	
3.2	Also demonstrate:	
3.2 (a)	how Essential Energy considers the control mechanisms are compliant with the *framework and approach paper*; and	
3.2 (b)	for *standard control services*, how Essential Energy considers the control mechanisms are also compliant with clause 6.2.6 and part C of Chapter 6 of the NER.	

Expenditure reporting

4. Capital Expenditure

RIN section	Requirement	Essential Energy Response
4.1	Provide justification for Essential Energy's total forecast capex, including the following information:	
4.1 (a)	why the total forecast capex is required for Essential Energy to achieve each of the objectives in clause 6.5.7(a) of the NER;	Essential Energy has built a bottom-up forecast which has been challenged by a top-down review of capital expenditure. The forecast is the result of an optimised portfolio and has been developed using historical performance, various modelling techniques and forecast efficiency improvements. Our Asset Management Plans describe our objectives, targets and performance relative to clause 6.5.7(a). Our Asset Management Plans (AMP) can be found at: > Supporting document 12.1.10 – Zone substations AMP > Supporting document 12.1.11 – Underground Network Assets AMP > Supporting document 12.1.12 – Secondary Systems Assets AMP > Supporting document 12.1.13 – Overhead Network Assets AMP The following documents provide further details: > Supporting document 12.1.5 - Network Strategy: Safety and Environment > Supporting document 12.1.6 – Network Strategy: Power Quality > Supporting document 12.1.7 – Network Strategy: Reliability > Supporting document 12.1.8 – Network Strategy: Distribution Growth, > Supporting document 12.1.9 – Network Strategy: Demand Management > Supporting document 12.1.15a to 12.1.15f – Major Project Options Reports. Further information on non-system capital expenditure can be found in the following business plans: > Supporting document 12.1.16 – Information technology business plan > Supporting document 12.1.17 – Fleet business plan > Supporting document 12.1.18 – Property business plan

RIN section	Requirement	Essential Energy Response
4.1 (b)	how Essential Energy's total forecast capex reasonably reflects each of the criteria in clause 6.5.7(c) of the NER;	Essential Energy has been focusing on significantly reducing costs by increasing efficiency, evaluating work programs to determine their value, then reshaping activities to extract more value. Using the Appraisal Value Framework described in Supporting document 12.1.1 – Risk Informed Optimisation, low-value programs have been either reduced to the lowest efficient minimum to meet compliance requirements, or cancelled to allow the most efficient use of funds to comply with our obligations and customers' expectations. Central to this approach is the need to maintain a good understanding of network condition so we can intervene at the most cost-efficient time within each asset's lifecycle. We have undertaken industry best practice and top-down analysis to ensure we are continually improving efficiency and to identify areas with opportunities for further improvement. Our investment optimisation process (described in Supporting document 12.1.1 – Risk Informed Optimisation) ensures our investment is prudent, realistic and efficient. Furthermore, our Asset Management and Business Plans listed in the response to 4.1(a) highlight Essential Energy's network needs.
4.1 (c)	how Essential Energy's total forecast capex accounts for the factors in clause 6.5.7(e) of the NER;	Essential Energy has addressed the factors in clause 6.5.7 (e) of the NER as follows: > **6.5.7 (e) (1) to (3) -** These clauses are deleted > **6.5.7 (e) (4) -** Although Essential Energy is in the bottom three DNSPs for Multilateral Total Factor Productivity (MTFP) according the latest Annual Benchmarking Report, we have improved our score by 6%—the second highest improvement for all distributors—and intend to keep improving during the next regulatory period. Our replication of the AER's repex models indicates our level of replacement capital expenditure for 2019-2024 is reasonable. We anticipate that a similar exercise by the AER will show the same. These results can be seen in Supporting document 12.1.1 – Risk Informed Optimisation and our Asset Management Plans, (see slide - Comparison to AER REPEX Benchmarks): o Supporting document 12.1.10 – Zone substations AMP o Supporting document 12.1.11 – Underground Network Assets AMP o Supporting document 12.1.12 – Secondary Systems Assets AMP o Supporting document 12.1.13 – Overhead Network Assets AMP > **6.5.7 (e) (5) -** Essential Energy's forecast capital expenditure for our 2019-24 Regulatory Proposal is lower than historical regulatory periods, as illustrated in the Capital Expenditure chapter of our Regulatory Proposal > **6.5.7 (e) (5A) -** Essential Energy has run a number of customer engagement forums and obtained feedback from customers that have framed our regulatory proposal and forecast expenditure. Subsequent sessions have been run to inform customers of the outcomes of their feedback in our Regulatory Proposal and to check alignment. For further details, see the Capital Expenditure and Customer Engagement chapters of our Regulatory Proposal, and the Network Strategy documents (supporting documents 12.1.5 through to 12.1.9).

RIN section	Requirement	Essential Energy Response
		- **6.5.7 (e) (6) -** Our forecast expenditure assumes that any increases to output and cost inputs will absorbed by further productivity improvements above those set out in our regulatory proposal The delivering value chapter of our regulatory proposal provides further information on our proposed efficiency savings as a result of our investment in ICT. Our unit rate methodology is set out in attachment R5 - Capital Unit Rates - Methods, Source Data & Results document). - **6.5.7 (e) (7) -** Essential Energy is focused on achieving lowest asset lifecycle cost, which includes the consideration of optimal and efficient operating and capital expenditure trade-offs. Capital investment options consider a range of possible solutions, including network and non-network options, with each option considering operating expenditure trade-offs in a risk versus value framework. Essential Energy has also invested in program and portfolio optimisation tools to assist in building our investment portfolio and program of works. We use this capability to optimise program options against risk and the value returned to develop an optimised portfolio. As the models that support our optimisation software are continually enhanced and refined, we expect to see further optimisation of our portfolio and subsequent efficient consideration of capital and operating expenditure trade-offs. - **6.5.7 (e) (8)** – Our capital expenditure forecast is consistent with the Service Target Performance Incentive Scheme and Demand Management Incentive Scheme. Further details can be found in supporting document 12.1.7 - Network Strategy: Reliability, supporting document 12.1.9 - Network Strategy: Demand Management and Attachment 8.2 to our regulatory proposal - Service Target Performance Incentive Scheme(STPIS) Approach Paper. - **6.5.7 (e) (9)** – Essential Energy does not have any related parties. All contracts Essential Energy has in place for the delivery of capital works are at arms' length from unrelated third parties. - **6.5.7 (e) (9A)** – Our capital expenditure forecast does not include any expenditure that should be more appropriately classed as a contingent project. - **6.5.7 (e) (10)** – Non-network alternatives are considered for our projects where appropriate. Further details can be found in supporting document 12.1.9 Network Strategy: Demand Management Strategy (Section 6 - Strategy) and supporting document 12.1.8 Network Strategy: Distribution Growth (Section 4.5 - Demand Management). - **6.5.7 (e) (11)** Presently, Essential Energy does not have any final RIT-D project assessment reports for the next regulatory period. These reports will be produced closer to the decision date. - **6.5.7 (e) (12)** There are no other factors that the AER has requested.
4.1 (d)	an explanation of how the plans, policies, procedures and regulatory obligations or requirements identified in Workbook 1 – regulatory determination, regulatory templates 7.1 and 7.3 have been used to develop forecast capex; and	Essential Energy's Asset Management System is directed by our Strategic Asset Management Plan and can be found at Attachment 12.1 to our regulatory proposal. Supporting this are Network Strategies (supporting documents 12.1.5 through to 12.1.9), Asset Management Plans (supporting documents 12.1.10 through to 12.1.13) and Business Plans (supporting documents 12.1.17 through to 12.1.19). Our Asset Management Plans and Business Plans demonstrate how these documents inform our decision-making.

RIN section	Requirement	Essential Energy Response
		Our Policies and Procedures that enable us to achieve our asset management objectives also support our plans which are available upon request.
4.1 (e)	an explanation of how each response provided to paragraph 4.1 (a) to (d) is reflected in any increase or decrease in expenditures or volumes, particularly between the current and forthcoming regulatory control periods, provided in Workbook 1 – regulatory determination, regulatory templates 2.1 to 2.11.	The Delivering Value, Risk Management and Capital Expenditure chapters of the Regulatory Proposal provides information on increases and decreases in capital expenditure. Supporting document 12.1.1 – Risk Informed Optimisation provides more detail on how some if the decreases in capital expenditure will be achieved.
4.2	Provide the model(s) and methodology Essential Energy used to develop its total forecast capex, including;	Note only
4.2 (a)	A description of how Essential Energy prepared the forecast capex, including:	A description of how Essential Energy prepared it total forecast capex is outlined in the delivering value, risk management and capital expenditure chapters of our Regulatory proposal. Further detail is included in the following supporting documents: > Supporting document 12.1.1 – Risk Informed Optimisation > Supporting document 12.1.5 - Network Strategy: Safety and Environment > Supporting document 12.1.6 – Network Strategy: Power Quality > Supporting document 12.1.7 – Network Strategy: Reliability > Supporting document 12.1.8 – Network Strategy: Distribution Growth, > Supporting document 12.1.9 – Network Strategy: Demand Management > Supporting document 12.1.10 – Zone substations AMP > Supporting document 12.1.11 – Underground Network Assets AMP > Supporting document 12.1.12 – Secondary Systems Assets AMP > Supporting document 12.1.13 – Overhead Network Assets AMP > Supporting document 12.1.16 – Information technology business plan > Supporting document 12.1.17 – Fleet business plan > Supporting document 12.1.18 – Property business plan > Supporting document 12.1.15a to 12.1.15f – Major Project Options Reports.
4.2 (a) i	how its preparation differed or related to budgetary, planning and governance processes used in the normal running of Essential Energy's business;	Essential Energy has made significant improvement in recent years in particular in the area of risk-based asset management, these improvements have aided and informed the preparation of the capital expenditure forecast for the 2019-24 regulatory period. Essential Energy is continuing its improvement journey to deliver value in line with customer value expectations and expected benefits from this improvement have been factored into its forward forecast expenditure. Further information can be found in the Risk Management and Capital Expenditure chapter of the Regulatory Proposal and Supporting document 12.1.1 – Risk Informed Optimisation.

RIN section	Requirement	Essential Energy Response
4.2 (a) ii	the processes for ensuring amounts are free of error and other quality assurance steps; and	We have conducted significant internal peer review for all elements of our total forecast capital expenditure. We also engaged an external consultant to undertake Risk versus Expenditure modelling for a further top-down view to validate our own modelling – this report can be found at supporting document 12.1.2 Risk versus expenditure assessment. Furthermore, an external review of all expenditure values was undertaken to ensure consistency.
4.2 (a) iii	if and how Essential Energy considered the resulting amounts, when translated into price impacts, were in the long-term interest of consumers.	We have designed Essential Energy's proposed capital expenditure plan for the 2019-24 regulatory period to serve the long-term interests of our customers while allowing us to adapt to our changing role in an evolving electricity industry. We used the customer values identified from our customer engagement to guide our risk-based approach to asset management, with a strong emphasis on affordability. We also undertook extensive modelling to understand the price impacts on customers of different levels of expenditure and Rate of Return outcomes. To reduce pricing pressures on our customers, our plan directs expenditure to where it will deliver the most value while sustainably managing our existing asset base through carefully targeted replacement and refurbishment programs. Further information can be found in the Capital Expenditure chapter of the Regulatory Proposal.
4.2 (b)	any source material used (including models, documentation or any other items containing quantitative data); and	All source material has been documented in our: > Asset Management Plans (supporting documents 12.1.9 through to 12.1.13) > Business Plans (supporting documents 12.1.16 through to 12.1.18) > Network Strategy documents (supporting documents 12.1.5 through to 12.1.9).
4.2 (c)	calculations that demonstrate how data from the source material has been manipulated or transformed to generate data provided in the regulatory templates in Workbook 1 – regulatory determination.	**Replacement capital expenditure (REPEX)** There were three parts to determining the data required for Workbook 1: > **Expenditure** – This was determined using program-based (supporting document 12.1.1 – Risk informed optimisation) mapping to the asset categories specified in regulatory template 2.2. This mapping was developed using subject matter expert analysis and historical project composition of programs. The split to specific voltages was determined by a weighted split of historical replacement rates and unit rate costs. > **Units** – Units were determined by dividing expenditure by unit rates. Unit rates were determined in most cases by using the average of the past two years of Category Analysis RIN data and applying efficiency reductions in each year of the forecasts. Only the last two years of RIN data was used as it represents present field efficiencies and data collection methodologies. > **Failure Rates –** This was determined using historical figures as the base failure rate and applying trend lines, depending on the expenditure profile selected for that asset category. Trends were determined using investment case trends or by historical analysis trending.

RIN section	Requirement	Essential Energy Response
		Augmentation capital expenditure (AUGEX) Refer to our responses in 6.2. **Connections** Refer to our responses in 7.1.
4.3	Identify which items of Essential Energy's forecast capex are:	Note only
4.3 (a)	derived directly from competitive tender processes;	All procurement for plant, material and outsourced labour is done through a competitive tender process. See Attachment R6 to this RIN Response - Procurement Procedure, and attachment R5 - Capital Unit Rate – methods, sources and results. Outsourced programs include overhead service replacement, FI relay replacement, pole staking and navigable waterways obligations. All other capital expenditure is delivered by internal labour. Our forecast unit rates are based on historical unit rates adjusted for efficiency savings we intend to realise over the regulatory period through our investment in innovation and technology. No contingency factors have been included in our system capital expenditure forecasts. A reasonable contingency has been included in some non-system projects.
4.3 (b)	based upon competitive tender processes for similar projects;	
4.3 (c)	based upon estimates obtained from contractors or manufacturers;	
4.3 (d)	based upon independent benchmarks;	
4.3 (e)	based upon actual historical costs for similar projects; and	
4.3 (f)	reflective of any amounts for risk, uncertainty or other unspecified contingency factors, and if so, how these amounts were calculated and deemed reasonable and prudent.	
4.4	Provide all documents which were materially relied upon and relate to the deliverability of forecast capex and explain the proposed deliverability.	Refer to supporting document 12.1.14– Network Delivery Plan 2019-24.
4.5	Describe each *capex category* and expenditures comprising these categories identified in the *regulatory templates,* including:	Note only
4.5 (a)	key drivers for expenditure;	Information on key drivers for our capital expenditure can be found in the following: > Capital Expenditure chapter of the Regulatory Proposal. > Key challenges section of our Asset Management Plans (supporting documents 12.1.9 through to 12.1.13). > Key challenges section of our Business Plans (supporting documents 12.1.16 through to 12.1.18). > Performance and gap analysis section of our Network Strategy documents (supporting documents 12.1.5 through to 12.1.9).

RIN section	Requirement	Essential Energy Response
4.5 (b)	an explanation of how expenditure is distinguished between:	Note only
4.5 (b) i.	greenfield driven and reinforcement driven augmentation capex;	The key driver is increases in network demand, with additionally the maintenance of network fault levels driving some reinforcement capex. Under Essential Energy's current connections policy (found at Attachment 12.2 to our Regulatory Proposal) Essential Energy does not fund greenfield network capex driven by a specific customer or developer. As a result of capex invested in the shared network, where the greenfield assets are the lowest cost solution to meet the identified need are primarily the only investment classified as greenfield. The allocation between driver is provided by the investment owner.
4.5 (b) ii.	*connections expenditure* and augmentation capex;	Refer to the Capital Expenditure chapter of the Regulatory Proposal and supporting document 12.1.8 - Distribution Growth Strategy.
4.5 (b) iii.	*replacement capex* driven by condition and asset replacements driven by other drivers (e.g. the need for greenfield or reinforcement driven augmentation capex); and	Essential Energy's replacement capex is predominantly driven by condition, with some compliance and safety driven capex. The majority of compliance and safety driven capex relates to our low clearance program – further information can be found is supporting document 12.1.13 – Overhead network assets AMP.
4.5 (b) iv.	any other capex category or opex category where Essential Energy considers that there is reasonable scope for ambiguity in categorisation.	We have not identified any other areas of ambiguity.

5. Replacement capital expenditure modelling

RIN section	Requirement	Essential Energy Response
5.1	In relation to information provided in Workbook 1 – regulatory determination, regulatory template 2.2 and with respect to the AER's repex model, provide:	The asset categories that have been used are those requested by the AER in regulatory template 2.2. The drivers are covered in detail in our Asset Management Plans (supporting documents 12.1.10 through to 12.1.13). The majority of replacement is based on the asset's condition. Replacement unit costs were not requested in the regulatory template and cannot be accurately calculated by dividing the dollars by the units. This information has been summarised in Attachment R7 to this RIN response (Essential Energy RIN REPEX Categories).
5.1 (a)	For individual asset categories in each asset group set out in the *regulatory templates,* provide in a separate document:	
5.1 (a) i.	a description of the asset category, including:	
5.1 (a) i. (A)	the assets included and any boundary issues (i.e. with other asset categories);	
5.1 (a) i. (B)	an explanation of how these matters have been accounted for in determining quantities in the age profile;	
5.1 (a) i. (C)	an explanation of the main drivers for replacement (e.g. condition); and	
5.1 (a) i. (D)	an explanation of whether the replacement unit cost provides for a complete replacement of the asset, or some other activity, including an extension of the asset's life (e.g. pole staking) and whether the costs of this extension or other activity are capitalised or not.	
5.1 (a) ii.	an estimate of the proportion of assets replaced for each year of the *current regulatory control period,* due to:	Asset categories have been provided by the AER in regulatory templates 2.2. All estimations have been adopted to include only costs and units that are associated with refurbishment due to condition. This information has been summarised in Attachment R7 to this RIN response (Essential Energy RIN REPEX Categories).
5.1 (a) ii. (A)	aging of existing assets (e.g. condition, obsolesce, etc.) that should be largely captured by this form of replacement modelling;	
5.1 (a) ii. (B)	replacements due to other factors (and a description of those factors);	
5.1 (a) ii. (C)	additional assets due to the augmentation, extension, development of the network; and	
5.1 (a) ii. (D)	additional assets due to other factors (and a description of those factors).	

RIN section	Requirement	Essential Energy Response
5.1 (b)	For the previous, current and forthcoming regulatory control periods, explain the drivers or factors that have changed network replacement expenditure requirements. Identify and quantify the relative effect of individual matters within the following categories:	Note only
5.1 (b) i.	rules, codes, license conditions, statutory requirements;	Rules, codes, licence conditions and statutory requirements have remained relatively stable as a driver of, or factor for, replacement capital expenditure. Changes to expenditure levels are a result of condition, introduction of a new investment framework and a new investment optimisation process. During the previous regulatory period, the NSW licence conditions were amended to remove schedule 1 – deterministic planning standards. Essential Energy used and continues to use probabilistic approaches to planning during the previous, current and forthcoming regulatory period. For further information can be found in our: > Asset Management Plans (supporting documents 12.1.10 through to 12.1.13) > Business Plans (supporting documents 12.1.16 through to 12.1.18) > Network Strategy documents (supporting documents 12.1.5 through to 12.1.9).
5.1 (b) ii.	internal planning and asset management approaches;	We have implemented an Investment Decision Optimisation approach and framework for asset management that is transforming the planning, scoping and selection process for our project portfolio. The key drivers for these projects are a combination of likelihood of failure and consequential asset risk, and value as per our appraisal value framework. This new process ensures both a top-down and bottom-up approach to our investment portfolio. Investment decisions also take into account feedback from our customer engagement process. Further information can be found in the Risk Management and Capital Expenditure chapters of the Regulatory Proposal.
5.1 (b) iii.	measurable asset factors that affect the need for expenditure in this category (e.g. age profiles, risk profiles, condition trend, etc.). Identify and quantify individual factors;	The vast majority of replacement capital expenditure projects relate to condition-based replacements i.e. assets which are about to fail, where it is not within our businesses risk appetite to allow the failure to occur. Further information can be found in the Risk Management and Capital Expenditure chapters of the Regulatory Proposal and Supporting document 12.1.1 – Risk Informed Optimisation.

RIN section	Requirement	Essential Energy Response
5.1 (b) iv.	(iv) the external factors that can be forecast and the outcome measured (e.g. demand growth, customer numbers) that affect the need for expenditure in this category. Identify and quantify individual factors, covering the forecasts and the outcome (external factors to be discussed here do not relate to changing obligations which are covered in paragraphs 11.3 and 11.8);	As discussed above the majority of our forecast replacement capex is driven by condition, with some safety and compliance driven capex. Essential Energy's forecast replacement capex is not driven by other external factors such as growth. Growth related capex is captured within augex. Further information can be found in: > The capital expenditure chapter of our regulatory proposal > Asset Management Plans (supporting documents 12.1.10 through to 12.1.13) > Network Strategy documents (supporting documents 12.1.5 through to 12.1.9).
5.1 (b) v.	technology/solutions to address needs, covering:	Note only
5.1 (b) v. (E)	network; and	We are investing significantly in IT to deliver further cost reductions and better value to our customers. Using new technology such as drones and LIDAR for inspection has improved the condition assessments of Essential Energy's assets. With more detailed visual assessments, replacement capital expenditure work can be accelerated or postponed depending on the characteristics of individual assets. Through field force automation, asset condition and consequence data has improved, improving our asset replacement strategies. Furthermore, scheduling efficiencies obtained through the rollout of smart devices and real-time resource scheduling will place downward pressure our capital unit rates. For more information regarding our technology investment and plans, refer to the Capital Expenditure, Innovation and Delivering Value chapters of our Regulatory Proposal.
5.1 (b) v. (F)	non-network.	
5.1 (b) vi.	any other significant matters.	No other significant matters have been noted outside of our regulatory proposal, attachments and supporting documents.

RIN section	Requirement	Essential Energy Response
5.1 (b) vii.	Identify and provide information or documentation to justify and support any responses to paragraph 5.1(b) (i)-(vi)	Supporting information is included in the Customer Engagement, Innovation, Delivering Value and Capital Expenditure chapters of the Regulatory Proposal. More detailed information is contained within the following: > Supporting document 12.1.1 – Risk Informed Optimisation > Supporting document 12.1.5 - Network Strategy: Safety and Environment > Supporting document 12.1.6 – Network Strategy: Power Quality > Supporting document 12.1.7 – Network Strategy: Reliability > Supporting document 12.1.8 – Network Strategy: Distribution Growth, > Supporting document 12.1.9 – Network Strategy: Demand Management > Supporting document 12.1.10 – Zone substations AMP > Supporting document 12.1.11 – Underground Network Assets AMP > Supporting document 12.1.12 – Secondary Systems Assets AMP > Supporting document 12.1.13 – Overhead Network Assets AMP > Supporting document 12.1.16 – Information technology business plan > Supporting document 12.1.17 – Fleet business plan > Supporting document 12.1.18 – Property business plan > Supporting document 12.1.15a to 12.1.15f – Major project Options Reports.
5.1 (b) vii.	The information provided above should at least distinguish between the asset categories listed in Workbook 1 – regulatory determination, regulatory template 2.2	Our regulatory proposal, attachments and supporting documents provide the information required as discussed above.

6. Augmentation capital expenditure

RIN section	Requirement	Essential Energy Response
6.1	Any instructions in this notice relating to the augex model must be read in conjunction with the augex model guidance document available on the AER's website (http://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/expenditure-forecast-assessment-guideline/final-decision).	Note only.
6.2	6.2 In relation to information provided in Workbook 1 – regulatory determination, regulatory template 2.4 and with respect to the AER's augex model:	Note only.
6.2 (a)	Separately for sub-transmission lines, sub-transmission and zone substations, HV feeders and distribution substations, Essential Energy must explain how it:	Note only.
6.2 (a) i.	Prepared the *maximum demand* data (weather corrected at 50 per cent *probability of exceedance*) provided in the asset status tables 2.4.1 to 2.4.4, including where relevant, explanations of each of:	Regarding Tables RIN tables 2.4.1 to 2.4.4, in general Essential Energy does not consider the use of the financial year as an appropriate method of segmenting load and demand data. Load and demand data is seasonal, so using the financial year boundaries splits the winter season in two. The years requested within the augmentation capital expenditure model are 2017-18 and 2013-14. As 2017-18 has not concluded, data is not available for this period. Given the seasonal issue, we have used (unless stated otherwise) 2016-17 data, which comprises Winter 2016 and Summer 2016-17. The 2013-14 data is taken from Winter 2013 and Summer 2013-14. Winter 2015 and Summer 2015-16 data was used for Sub-transmission lines. Maximum demand data was sourced from the DAPR publications. Maximum demand was calculated by modelling each network region to identify the percentage load flow from the bulk supply point. Earlier data was published in amps, so was converted to MVA using the nominal line voltage. Sub-transmission and zone substations — weather-corrected maximum demands (MW) for each time period and season were calculated from system demand data to provide forecasts for the 2017 DAPR. The maximum value across both seasons was used and converted to MVA using the appropriate power factor for that site. HV feeders — maximum demand data (MVA) was sourced from the annual RIN. This data was weather-corrected by applying the ratio of weather-corrected to maximum demand values from the relevant zone substation. The value was then converted to MW using the power factor of the relevant zone substation from the dominant season.

RIN section	Requirement	Essential Energy Response
6.2 (a) i. (A)	how this value relates to the *maximum demand* that would be used for normal planning purposes;	Regarding tables 2.4.1 to 2.4.3, for planning purposes, the demand is presented as we would for a first pass to evaluate the likelihood of reaching a constraint on the particular asset, including voltage and thermal issues under normal conditions. The same method would also be used to evaluate network demands under N-1 conditions where appropriate. Once a potential constraint had been identified, a more thorough review of actual demands would be undertaken, taking into account a more thorough understanding of the diversities of connected assets, generation and large customers.
6.2 (a) i. (B)	whether it is based upon a measured value, and if so, where the measurement point is and how abnormal operating conditions are allowed for;	Where possible, the data is sourced from metering data on the network. Essential Energy removes outliers or evidence of switching (abnormal configuration) from the data to the extent possible.
6.2 (a) i. (C)	whether it is based on estimated (rather than actual measured) demand, and if so, the basis of this estimation process and how it is validated; and	The majority of calculations start from data that is measured. In some cases, such as sub-transmission lines, the data is apportioned or —as for HV feeders—the power factors are determined from the appropriate zone substation.
6.2 (a) i. (D)	the relationship of the values provided to raw unadjusted maximum demand; and the relationship of the values provided to the values that could be expected from weather corrected maximum demand measures that reflect a 10 per cent probability of exceedance year.	This varies on a zone substation by zone substation basis. The weather-corrected (50 per cent) maximum demand moves either side of the raw unadjusted values and, by definition, would on average be expected to be larger 50% of the time. This depends on the actual weather conditions each year. We would expect that the 10% probability of exceedance would be a larger value.
6.2 (a) ii.	Determined the rating data provided in the asset status *tables* 2.4.1 to 2.4.4, including where relevant:	Note only.

RIN section	Requirement	Essential Energy Response
6.2 (a) ii (A)	the basis of the calculation of the ratings in that segment, including asset data measured and assumptions made; and	Sub-transmission lines — Ratings are based on published ratings in the DAPR publications. They were calculated using the conductor type, span length, span height, and assumptions of weather conditions to determine the maximum current that can flow while maintaining minimum clearances to the ground. A single sub-transmission line may contain several sections of different rating; the rating used was from the minimum rating of all the sections for a given sub-transmission line. Sub-transmission and zone substations — The rating information is determined from the nameplate information. Essential Energy defines the normal cyclic rating as 110% for the in-service nameplate. The normal cyclic total has been identified as the same value as the transformer normal cyclic rating, and the N-1 Emergency MVA is the nameplate rating minus the largest transformer size (assuming it is out of service), multiplied by 110%. HV feeders — Thermal rating (in amps) were determined from the cable/conductor type at the start of the feeder and the appropriate ratings in standard weather conditions. The operating ratings were the minimum rating between the thermal rating and the rating based on 10% of the average fault level. This is an indicative limit for load-based voltage constraints, although not necessarily for voltage bandwidth issues. The current rating was converted to 3 phase MVA ratings using the voltage of the feeder. Distribution sub-ratings were taken as nameplate ratings
6.2 (a) ii (B)	the relationship of these ratings with Essential Energy's approach to operating and planning the network. For example, if alternative ratings are used to determine the augmentation time, these should be defined and explained.	Regarding Tables 2.4.1, 2.4.3 and 2.4.4, for planning purposes, these are generally the ratings that would be used as a first pass to evaluate the likelihood of reaching a constraint on the particular asset for thermal issues under normal conditions. The same method would be used to evaluate network demands under N-1 conditions where appropriate. Once a potential constraint had been identified, a more thorough review of actual ratings would be undertaken, taking into account the more thorough understanding of asset condition and specifications. For voltage-based issues, the ratings noted will have little impact on the true capacity of the network. For Table 2.4.2, the ratings generally have no relationship with the augmentation required in the majority of cases in a voltage-constrained network, as augmentation will be completed further out in the network or consist of regulating devices etc.
6.2 (a) iii	Determined the growth rate data provided in the asset status tables 2.4.1 to 2.4.4. This should clearly indicate how these rates have been derived from maximum demand forecasts or other load forecasts available to Essential Energy.	Annual growth rates are based around the forecast maximum demands published in the 2017 DAPR. Zone substation growth rates of the dominant season were applied to associated zone substation and HV feeders. Line forecasts were applied to sub-transmission lines. Distribution substation forecasts used an average of the HV feeder growth rates.
6.2 (b)	In relation to the capex-capacity table 2.4.6, Essential Energy must explain:	Note only
6.2 (b) i	the types of cost and activities covered. Clearly indicate what non-field analysis and management costs (i.e. direct overheads) are included in the *capex* and what proportion of *capex* these cost types represent;	No non-field analysis and management costs are included, so these cost types represent 0% of the reported augmentation capital expenditure costs in Table 2.4.6.

RIN section	Requirement	Essential Energy Response
6.2 (b) ii	how it determined and allocated *actual capex* and capacity to each of the segment groups, covering:	Actual capital expenditure was allocated to each segment in proportion to the PeopleSoft data and data mapping provided by subject matter experts. The total actual values directly align with the values reported as part of the annual CA RIN.
6.2 (b) ii (A)	the process used, including assumptions, to estimate and allocate expenditure where this has been required; and	
6.2 (b) ii (B)	the relationship of internal financial and/or project recording categories to the segment groups and process used.	
6.2 (b) iii	how it determined and allocated estimated/*forecast capex* and capacity to each of the segment groups, covering:	The estimated forecast capital expenditure directly aligns with current projects and programs for the forthcoming period. The expenditure for each relevant project or program is mapped to a specific segment by either project details or by the program owner. Forecast capacity is determined by dividing the forecast expenditure at segment level by the historic unit rate for capacity additions, as defined in Table 2.4.5.
6.2 (b) iii (A)	the relationship of this process to the current project and program plans; and	The process of allocating estimated/forecast capex relates directly to the program and project forecasts in Essential Energy's network investment portfolio. These are allocated to categories based on their historical relationship to connections and asset categories. The process used to derive forecast capacity will have a relationship with the current plans, however the variability in the capacity added indicates that the relationship is poorly correlated.
6.2 (b) iii (B)	any other higher-level analysis and assumptions applied.	Following the approach outlined in our response to 6.2 (b) iii (A), the following high-level assumptions are applied to break down the high-level categories further: > Distribution HV feeders are broken down by the percentage split in capacity added to distribution feeders. > Distribution Transformers are split by percentage capacity added between underground and overhead. > Changes in Type 2 – normal cyclic and Type 3 - N-1 emergency ratings are forecast in the same ratio as historic Type 2 – normal cyclic and Type 3 - N-1 emergency capacity additions per unit of Type 1 - name plate capacity added.
6.2 (c)	Describe the projects and programs Essential Energy has allocated to the un-modelled augmentation categories in table 2.4.6, covering:	Note only.
6.2 (c) i	the proportion of un-modelled augmentation capex due to this project or program type;	Essential Energy has allocated some load control system expenditure to unmodeled augmentation as it is not related to a defined element/segment of network capacity. Also, the minor sub-transmission system augmentation program associated with operational system improvements, which typically relates to individual switches or line connections, has not been included. It is not directly related to a defined capacity addition and will typically not add additional rated capacity; instead, it will improve operability of existing capacity.

RIN section	Requirement	Essential Energy Response
6.2 (c) ii	the primary drivers of this capex, and whether in Essential Energy's view, there is any secondary relationship to maximum demand and/or utilisation of the Essential Energy network; and	Load control system expenditure has a secondary relationship to maximum demand and network utilisation. This reduction, although effective, is not attributable to an individual segment. Minor sub-transmission augmentation has minimal relationship to maximum demand.
6.2 (d)	Separately for each network segment that Essential Energy defined in the model segment data table 2.4.5, whether the outcome of such a project or program, whether intended or not, should be an increase in the capability of the Essential Energy network to supply customer demand at similar service levels, or the improvement in service levels for a similar customer demand level:	The outcome of Essential Energy's augmentation capital expenditure programs relating to the assets in 2.4.5 is maintaining overall service levels on average for network customers.
6.2 (d) i	Describe the *network* segment, including:	Essential Energy has 12 network segments: - HV Feeder - Urban – Positive - HV Feeder - Urban – Negative - HV Feeder - Short Rural – Positive - HV Feeder - Short Rural – Negative - HV Feeder - Long Rural – Positive - HV Feeder - Long Rural – Negative - Distribution Substation Padmount - Distribution Substation – Poletop - Sub-transmission Feeder – Positive - Sub-transmission Feeder – Negative - Zone & Sub Substations – Positive - Zone & Sub Substations – Negative Of the 12 network segments, there are 4 asset hierarchies: - Sub-transmission feeder - Zone & Sub Substations - HV feeder - Distribution Substation. The boundaries of these being (with very few exceptions); **Sub-transmission feeder**; from bulk supply point to zone substation or zone substation to zone substation. **Zone & Sub Substations:** sites where voltages are converted between primary and secondary voltages for further sub-transmission feeders, HV feeders etc. **HV feeders:** Connecting Zone & Sub Substations with distribution substations. **Distribution Substations:** sites where voltages are converted to LV for connection to customers. Five sub asset types have been identified based on substantial differences in cost and network capacity between types, these are: - Within HV feeders; Long Rural, Short Rural and Urban. - Within Distribution Substations; Padmount and Poletop. Finally, segments have been defined by whether the growth rate is positive or negative, as the AUGEX model doesn't reflect the
6.2 (d) i (A)	the boundary with other connecting *network* segments; and	
6.2 (d)i (B)	the main reasoning for the individual segment (e.g. as opposed to forming a more aggregate segment).	
6.2 (d) ii	Explain the utilisation threshold statistics provided (i.e. the mean and standard deviation), including:	
6.2 (d) ii (A)	the methodology, data sources and assumptions used to derive the parameters;	
6.2 (d)ii (B)	the relationship to internal or external planning criteria that define when an *augmentation* is required;	
6.2 (d) ii (C)	the relationship to actual historical utilisation at the time that *augmentations* occurred for that asset category;	
6.2 (d) ii (D)	Essential Energy's views on the most appropriate probability distribution to simulate the augmentation needs of that network segment; and	
6.2 (d) ii (E)	the process applied to verify that the parameters are a reasonable estimate of utilisation limit for the *network* segment.	

RIN section	Requirement	Essential Energy Response
		augmentation requirements of the combination of positive and negative growth rates. All utilisation limits are based on actual projects/upgrades and demand. The exception is 2.4.4, which is based on a subset of actual projects/upgrades and extrapolated to infer total class outputs. The use of the AUGEX model has been problematic for Essential Energy's network. Many of the issues are due to the augmentation of Essential Energy's network driven by voltage bandwidth and fault level constraints. While related to demand, these do not align with the underlying premise of the AUGEX model. The problems identified then lead to issues with the relationship between utilisation and augmentation and the statistical distribution, as evidenced by large standard deviations.
6.2 (d) (iii)	Regarding the *augmentation* unit cost and capacity factor provided, provide an explanation of each of:	Note only.
6.2 (d) (iii)(A)	the methodology, data sources and assumption used to derive the parameters;	**Augmentation unit cost- HV feeders** At the reliability category level, the investment over the period (defined by Network Planning Database), which meets the definition of augmentation expenditure, is divided by the ratcheted HV feeder capacity over the same period (defined by the feeder ratings sheet). Capacity factor is defined as the ratcheted capacity at the end of the period divided by the starting capacity. **Distribution Substations** Both capacity and level of investment are captured as part of project-level information in the same Network Planning Database system. As such, no data matching is required, and the unit rate is simply the capacity added for the period divided by project investment totals, where the project is defined as an augmentation project. The capacity factor is based on all distribution substation upgrades during the period that included utilisation information. The average of the post-investment capacity divided by the pre-investment capacity is used. **Sub-transmission feeders** Due to the far smaller number of projects, and the fact capacity added is defined as part of the project, the unit rate is defined as an average of the capacity unit rate for all projects completed during the period. The source of this detail is project investment documentation for the period. Capacity factor is defined as the change in capacity over the original capacity for all AUGEX upgrade projects over the period. **Zone substations** Similar to distribution feeders, the unit rate is defined by the changes in Type 1 capacity over the period divided by all augmentation investment directed at zone substations during the period. The capacity factor is defined as the average of all the capacity Type 1 additions divided by the previous capacity for the period of analysis. Note, where categories are required to be split, the same high-level assumptions as for 6.2 (b) iii (B) are used.
6.2 (d) (iii)(B)	the relationship of the parameters to actual historical *augmentation* projects, including the capacity added through those projects and the cost of those projects;	All the defined augmentation unit costs and capacity factors relate directly to historical projects completed during the period of analysis. Depending on this asset category, this is either calculated at the project level or at the asset category level, using total capacity change and total investment over the same period.

RIN section	Requirement	Essential Energy Response
6.2 (d) (iii)(C)	the possibility of double-counting in the estimates, and processes applied to ensure that this is appropriately accounted for (e.g. where an individual project may add capacity to various segments); and	The asset categories used mean the risk a project has been double-counted is negligible. Specifically, sub-transmission and zone substation projects are managed separately to their related distribution feeder investments, so no double-counting is captured as part of this analysis.
6.2 (d) (iii)(D)	the process applied to verify that the parameters are a reasonable estimate for the *network* segment.	Subject matter experts have reviewed the reasonableness of the outputs of analysis to determine both capacity unit costs and capacity factors. This review included comparison with Essential Energy's current Long Run Marginal Cost.
6.2 (e)	Explain the factors Essential Energy considers may result in different augmentation requirements for itself as compared to other NEM DNSPs. Essential Energy must account for the degree that different augmentation requirements are driven by differences in asset utilisation and maximum demand growth. Essential Energy must also explain all other factors, specific to its network, which would result in different augmentation requirements when compared to a DNSP with similar asset utilisation and maximum demand growth. The explanation must clearly indicate those factors that may impact:	The factors that may result in different augmentation requirements for Essential Energy include: > The nature and type of the overhead construction used i.e. Essential Energy's network contains a large rural network with small-bodied conductors, which results in voltage and protection type constraints. > Use of both distribution substations with minimal taps and small distribution substations (5kVA) in rural areas, which require upgrading due to lifestyle changes. > The high penetration of renewables, leading to voltage bandwidth issues when demand levels do not reduce at the same rate as solar growth. > As discussed in section 6.2 (d) i, Essential Energy's network and augmentation requirements cause issues with the AUGEX model as it is currently defined.
6.2 (e) i	the maximum achievable utilisation of assets for Essential Energy; and	Essential Energy's utilisation rates are generally low when compared to other DNSPs. This is largely due to the nature of our network and low network demands over sparse areas. For example, economic transformer sizing leads to a gap between demand and capacity at lower network demands; so do single or dual transformer sites, voltage-related augmentation, fault-level-related augmentations etc. The maximum achievable utilisation of assets is a function rather than a definitive number, which varies across each asset and is based on: > The redundancy requirements—for example, where N-1 is calculated to be required, based on a probabilistic analysis of the value of customer reliability, which itself is a function of the probability of asset failure, the probable duration and customer load at the time of the outage. > The location of the asset and the temperature in the region. > The consequence of the failure of the asset. > The growth rate of the area and hence the available lead time to construction and commissioning of the asset. > The voltage bandwidth of the asset, which is a function of the upstream impedance to the asset and the load and generation serviced by the asset. It should be noted that voltage bandwidth does not appear to be considered in the AUGEX model. > The ability to detect faults at the end of the asset, which is a function of the upstream impedance to the asset, the load serviced by the asset and the existing protection devices on the asset.

RIN section	Requirement	Essential Energy Response
6.2 (e) ii	the likely *augmentation* project and/or cost.	It is likely that Essential Energy’s unit cost for adding capacity to linear assets is higher than the NEM average. The driver for this is linked to the maximum achievable utilisation when ratings are determined on a thermal basis, using the first trunk segment of a feeder. As Essential Energy's network is predominately voltage-constrained rather than thermally-constrained, our current approach to feeder rating does not accurately capture the driver for augmentation or the change in capacity that results from an investment. To improve our ability to forecast system utilisation as well as feeder-based forecasts, we are developing the ability to rate feeders consistently, based on where voltage constraints are most likely to emerge. This is not currently possible, so thermal ratings have been used to determine feeder ratings.
6.2 (e)	For each significant factor discussed, Essential Energy must indicate relevant model segments and estimate the impact these factors will have on its augmentation levels and associated capex compared to other DNSPs.	Given Essential Energy's relatively weak rural network and the impact of voltage bandwidth on augmentation requirements, changes in load or generation can have much greater impact on our augmentation costs than would be experienced by more urban DNSPs.

7. Connections Expenditure

<table>
<tr><th>RIN section</th><th>Requirement</th><th>Essential Energy Response</th></tr>
<tr><td>7.1</td><td>Provide and describe the methodology and assumptions used to prepare the forecasts of connection works including:</td><td>Note only</td></tr>
<tr><td>7.1 (a)</td><td>Estimation of connection unit costs for each customer type; and</td><td>For each customer type, the forecast costs for distribution substation installed and HV and LV augmentation (including new relays for residential customers) were added to estimate the cost metrics by connection classification.</td></tr>
<tr><td>7.1 (b)</td><td>Connection volumes for each customer type.</td><td>The annual rate of change forecast in Table 6.2 (net forecast of customer numbers - see Attachment 14.1 (Electrical energy and customer number projections for Essential Energy in New South Wales to 2029-30), were used to forecast the additional customers expected over time. The starting point was the number of connections added to the network in 2016-17.</td></tr>
<tr><td>7.2</td><td>Essential Energy must provide its estimation of customer contributions based upon the estimated life and revenue to be recovered from connection assets, including:</td><td rowspan="4">Essential Energy has forecast future customer contributions based on historic actuals and any known impacts to future customer contributions. We used the following methods to derive customer contribution actuals:
> Capital Contributions
o Extracted from Peoplesoft General Ledger.
o Capital Contributions income used as a proxy for Connections expenditure.
o Each project categorised with reference to ‘Project Name’ into ‘Connection Subcategory’ and ‘Connection Classification’. All assumed to be Simple Connections.
> Gifted Assets
o Extracted from Peoplesoft General Ledger.
o Gifted Asset Registers reconciled from Contestable Works Management System (CWMS) to Peoplesoft General Ledger for financial years 2012 to 2017.
o ‘Asset Type’ field from the CWMS used to classify each project into ‘Connection Subcategory’ and ‘Connection Classification’. All assumed to be Simple Connections.
o Financial years 2009 to 2011 did not have detailed project information available, so were apportioned across ‘Connection Subcategory’ and ‘Connection Classification’ using FY12 information.
o</td></tr>
<tr><td>7.2 (a)</td><td>the expected life of the connection;</td></tr>
<tr><td>7.2 (b)</td><td>the average consumption expected by the customer over the life of the connection; and</td></tr>
<tr><td>7.2 (c)</td><td>any other factors that influence the expected recovery of the Essential Energy network use of system charge to customers.</td></tr>
</table>

8. Non-network alternatives

RIN section	Requirement	Essential Energy Response
8.1	Identify the policies and strategies and procedures in the response to Workbook 1 – regulatory determination, regulatory template 7.1 which relate to the selection of efficient non-network solutions.	Essential Energy's policies and strategies relating to efficient selection of non-networks solutions include: > Supporting document 12.1.9 – Network Strategy: Demand Management > Attachment R8 to this RIN response - Our Demand Side Engagement Strategy. > Attachment R9 to this RIN response - Company Policy – Demand Management.
8.2	Explain the extent to which the provision for efficient non-network alternatives has been considered in the development of the *forecast capex* proposal and the forecast opex proposal.	We have outlined a non-network alternative program. This has decreased our forecast capital expenditure by a proportional amount. Further information can be found in: > Supporting document 12.1.9 – Network Strategy: Demand Management We are also trialling non-network alternatives.
8.3	Identify each non-network alternative that Essential Energy has:	Note only
8.3 (a)	commenced during the *current regulatory control period*; and	A multitude of non-network projects were undertaken during the current regulatory period. They included: > Customer payments for disconnection and alternate energy supply systems. > Networks Renewed- a virtual power plant of customer-owned battery storage and solar PV systems (DMIA). > Network technology roadmap (DMIA). > Global best practice Demand Management Review (DMIA). > Off-grid Opportunity Review. > Off-grid implementation (DMIA). > Peer-to-peer Demand Management Opportunities Review (DMIA). > ZS capacitor banks. > FI relay replacements. > FI plant installations. > Introduction of a demand network charge for small customers (identified in Essential Energy's Tariff Structure Statement). Ongoing programs include: > Capacitor package development (DMIA). > 3ph Low voltage regulators (DMIA). > Switched reactor trial (DMIA). > 3 phase statcoms at Bega/Tathra (DMIA). > Single phase four quadrant inverter with lithium ion energy storage at Pappinbarra (DMIA). >
8.3 (b)	selected to commence during, or will continue into, the *Forthcoming regulatory control period.*	As well as programs funded out of DMIA, we have included a non-network alternative program. Further information can be found in Supporting document 12.1.9 – Network Strategy: Demand Management.

RIN section	Requirement	Essential Energy Response
8.4	For each non-network *alternative* identified in the response to paragraph 8.3, provide a description, including cost and location.	> DMIA projects are described in the yearly RIN supporting information for DMIA. > ZS capacitor banks, as outlined in the regulatory template. > 44,699 FI relays were replaced to the end of FY17 and by the end of FY19 it is estimated approximately another 30,000 FI relays will be replaced. One new FI plant was installed at Dubbo South, five FI plants were replaced across Moree, Eulomogo, Leeton, Orange (No.1 Plant) and Galloway St to the end of FY17. Four legacy plant upgrades are planned for completion by the end of FY19. > Movement of customers across network charges is based on providing customers with more cost-reflective options. Further information can be found in Chapter 5 of Essential Energy's Tariff Structure Statement for 2019-24 > A non-network alternative program is outlined in found in Supporting document 12.1.9 – Network Strategy: Demand Management. Locations are yet to be determined.
8.5	Provide, for each year of the current regulatory control period, and for the forthcoming regulatory control period, details of each payment made, or expected to be made, by Essential Energy to an Embedded Generator in reflection any costs avoided by deferring augmentation of:	Note only.
8.5 (a)	Essential Energy's distribution network; or	No payments have been made to embedded generators as a result of deferring augmentation. We are continually investigating making payments to embedded generators to defer augmentation capital expenditure.
8.5 (b)	the relevant transmission network.	

9. Forecast input price changes

RIN section	Requirement	Essential Energy Response
9.1	Provide, in Workbook 1 – regulatory determination, regulatory template CPI series, the CPI series and index used by Essential Energy in its forecast capex proposal and the forecast opex proposal.	Provided in Reset Table, CPI Series Tab.
9.2	Provide, in Workbook 1 – regulatory determination, regulatory template 2.14, the capex and opex price changes assumed by Essential Energy in its forecast capex proposal and the forecast opex proposal. All price changes must be expressed in percentage year on year real terms	Provided in Table 2.14.
9.3 (a)	Provide the model(s) used to derive and apply the materials price changes, including model(s) developed by a third party;	Essential Energy has assumed materials price changes will not exceed inflation.
9.3 (b)	Provide in relation to labour escalators, a copy of the current Enterprise Bargaining Agreement or equivalent agreement; and	Attachment R10a and R10b to this RIN response contains copies of Essential Energy's proposed Enterprise Agreement (EA) and the proposed Far West Enterprise Agreement. The proposed EAs cover the period through to 30 June 2021. It limits wage increases to no more than 2.5%, which is equal to our forecast CPI rate. As such, we have not applied labour escalation to Standard Control Services for the first two years of the 2019-24 regulatory period. For the 2021-22 through to 2023-24 years, we have applied labour escalation above CPI, as calculated by CEG. CEG's report can be found at supporting document 9.2.1 Labour escalation factors affecting expenditure forecasts. However, these increases are offset by assumed efficiency savings over and above the cost reductions set out in our regulatory proposal for standard control services. Labour escalation rates in accordance with our EA and CEG's report have been built into the Ancillary Network Services prices on the assumption that (a) these services should be fully cost-reflective and (b) efficiency savings will not apply to the build-up of these individual customer services i.e. the hours of work will not change. The terms and conditions which currently apply are those contained in the Essential Energy Workplace Determination 2016 and the Essential Energy Far West (Electricity) Enterprise Agreement 2016. The proposed enterprise agreements which replace these instruments have been voted on and approved by a valid majority of employees, however, the agreements remain with the Fair Work Commission for approval. At the time of this submission, the proposed agreements have not yet been approved. The proposed agreements will take effect seven days after approval is given by the Fair Work Commission.

RIN section	Requirement	Essential Energy Response
9.3 (c)	Provide documents supporting or relied upon that explain the change in the price of goods and services purchased by Essential Energy, including evidence that any materials price forecasting method explains the price of materials previously purchased by Essential Energy.	To calculate assumed price and output growth rates, we used an excerpt from the AER's operating expenditure model. Attachment R11 to this RIN response contains the Opex Rate of Change model. This approach uses forecast customer numbers, circuit length and ratcheted maximum demand to determine price and output rates of change - as shown in Table 2.14 Forecast price changes. As discussed above, these amounts have also been assumed to be offset by efficiency savings, over and above the cost reductions set out in our regulatory proposal for standard control services as shown in Table 2.16.1 - Standard Control Services - Opex by driver.
9.4	Provide also an explanation of	Note only
9.4 (a)	the methodology underlying the calculation of each price change, including:	As discussed in our answer to 9.3(b) and 9.3(c), labour escalation has been provided by CEG (supporting document 9.2.1 Labour escalation factors affecting expenditure forecasts) and price and output growth were calculated using an excerpt of the AER's operating expenditure model (Attachment R11 to this RIN response contains the Opex Rate of Change model.).
9.4 (a) i	sources;	
9.4 (a) ii	data conversions;	
9.4 (a) iii	the operation of any model(s) provided under paragraph 9.3(a); and;	
9.4 (a) iv	the use of any assumptions such as lags or productivity gains;	As discussed above, a significant assumption is that any increase in costs due to forecast price and output growth will be offset by efficiency gains over and above the cost reductions set out in our regulatory proposal for standard control services.
9.4 (b)	whether the same price changes have been used in developing both the forecast capex proposal and forecast opex proposal; and	The same assumptions have been applied to both operating and capital expenditure forecasts.
9.4 (c)	if the response to paragraph 9.4(b) is negative, why it is appropriate for different expenditure escalators to apply	
9.5	If an agreement provided in response to paragraph 9.3(b) is due to expire during the forthcoming regulatory control period, explain the progress and outcomes of any negotiations to date to review and replace the current agreement	We expect Essential Energy's Enterprise Agreement and the Far West Enterprise Agreement to be ratified by the Fair Work Commission in the near future. They will be valid seven days thereafter, until 30 June 2021. Negotiations for the following EBA will not commence until 1 July 2020 i.e. one year out from the expiry date of the new EBA.

10. Operating and maintenance expenditure

RIN section	Requirement	Essential Energy Response
10.1 (a)	Provide: the model(s) and the methodology Essential Energy used to develop its total forecast opex;	Information supporting how Essential Energy developed its total opex forecast is contained within: > The Our Customer Engagement, Delivering Value and Operating Expenditure chapters of our regulatory proposal > Attachment 11.3 to our regulatory proposal; - Standard Control opex approach > Supporting document 11.3.2 – Opex Plan - Routine inspection > Supporting document 11.3.3 – Opex Plan - Planned maintenance > Supporting document 11.3.4 – Opex Plan - Unplanned maintenance > Supporting document 11.3.5 – Opex Plan – Vegetation management > Supporting document 11.3.6 – Overhead Plan – 'Corporate' > Supporting document 11.3.7 – Overhead Plan – Network Indirect 'Plan' > Supporting document 11.3.8 – Overhead Plan – Network Indirect 'Operate & Execute' > Supporting document 11.3.9 – Overhead Plan – Network Indirect 'Support'
10.1 (b)	justification for Essential Energy's total forecast opex, including:	The justification of Essential Energy's forecast opex is set out in the information listed in the response to 10.1 (a)
10.1 (b) i	why the proposed total forecast opex is required for Essential Energy to achieve each of the objectives in section 6.5.6(a) of the NER;	Essential Energy's proposed forecast opex meets the objectives set out in the NER and has been demonstrated throughout the below information: > The delivering value and operating expenditure forecast chapters of our regulatory proposal > Attachment 11.3 to our regulatory proposal; - Standard Control Opex Approach > Supporting document 11.3.2 – Opex Plan - Routine inspection > Supporting document 11.3.3 – Opex Plan - Planned maintenance > Supporting document 11.3.4 – Opex Plan - Unplanned maintenance > Supporting document 11.3.5 – Opex Plan – Vegetation management > Supporting document 11.3.6 – Overhead Plan – 'Corporate' > Supporting document 11.3.7 – Overhead Plan – Network Indirect 'Plan' > Supporting document 11.3.8 – Overhead Plan – Network Indirect 'Operate & Execute' > Supporting document 11.3.9 – Overhead Plan – Network Indirect 'Support'

RIN section	Requirement	Essential Energy Response
10.1 (b) ii	how Essential Energy's total forecast opex reasonably reflects each of the criteria in clause 6.5.6(c) of the NER; and	Essential Energy's proposed forecast opex reflects the criteria set out in the NER and has been demonstrated throughout the below information: > The delivering value, benchmarking and operating expenditure forecast chapters of our regulatory proposal > Attachment 11.3 to our regulatory proposal - Standard Control Opex Approach > Attachment 13.2 to our regulatory proposal – Economic benchmarking analysis (Frontier Economics) > Supporting document 11.3.2 – Opex Plan - Routine inspection > Supporting document 11.3.3 – Opex Plan - Planned maintenance > Supporting document 11.3.4 – Opex Plan - Unplanned maintenance > Supporting document 11.3.5 – Opex Plan – Vegetation management > Supporting document 11.3.6 – Overhead Plan – 'Corporate' > Supporting document 11.3.7 – Overhead Plan – Network Indirect 'Plan' > Supporting document 11.3.8 – Overhead Plan – Network Indirect 'Operate & Execute' > Supporting document 11.3.9 – Overhead Plan – Network Indirect 'Support'
10.1 (b) iii	how Essential Energy's total forecast opex accounts for the factors in clause 6.5.6(e) of the NER;	Essential Energy has addressed the factors in clause 6.5.6 (e) of the NER as follows: > **6.5.6 (e) (1) to (3) -** These clauses are deleted > **6.5.6 (e) (4) -** Essential Energy's benchmarking performance has improved significantly as shown in the AER's most recent annual benchmarking report. Essential Energy believes a suite of benchmarking model should be used to assess the efficiency of a DNSP. Attachment 13.2 to our regulatory proposal – Economic benchmarking analysis (Frontier Economics), provides a suite of benchmarking tools which show Essential Energy's base year operating expenditure is efficient. > **6.5.6 (e) (5) -** Essential Energy's forecast operating expenditure for our 2019-24 Regulatory Proposal is lower than historical regulatory periods, as illustrated in the Operating Expenditure chapter of our Regulatory Proposal > **6.5.6 (e) (5A) -** Essential Energy has run a number of customer engagement forums and obtained feedback from customers that has framed our regulatory proposal and forecast expenditure. Subsequent sessions have been run to inform customers of the outcomes of their feedback in our Regulatory Proposal and to check alignment. For further details, see the Operating Expenditure and Customer Engagement chapters of our Regulatory Proposal. > **6.5.6 (e) (6) -** Our forecast expenditure assumes that any increases to output and cost inputs will absorbed by further productivity improvements above those set out in our regulatory proposal. The delivering value chapter of our regulatory proposal provides further information on our proposed efficiency savings as a result of our investment in ICT. Further information can be found at Attachment 11.3 to our regulatory proposal - Standard Control

RIN section	Requirement	Essential Energy Response
		Opex Approach and supporting documents 11.3.2 through to 11.3.9. > **6.5.6 (e) (7) -** Essential Energy is focused on achieving lowest asset lifecycle cost, which includes the consideration of optimal and efficient operating and capital expenditure trade-offs. Capital investment options consider a range of possible solutions, including network and non-network options, with each option considering operating expenditure trade-offs in a risk versus value framework. Essential Energy has also invested in program and portfolio optimisation tools to assist in building our investment portfolio and program of works. We use this capability to optimise program options against risk and the value returned to develop an optimised portfolio. As the models that support our optimisation software are continually enhanced and refined, we expect to see further optimisation of our portfolio and subsequent efficient consideration of capital and operating expenditure trade-offs. > **6.5.6 (e) (8)** – Our operating expenditure forecast is consistent with the Service Target Performance Incentive Scheme and Demand Management Incentive Scheme. Further details can be found in supporting document 12.1.7 - Network Strategy: Reliability, supporting document 12.1.9 - Network Strategy: Demand Management and Attachment 8.2 to our regulatory proposal - Service Target Performance Incentive Scheme(STPIS) Approach Paper. > **6.5.6 (e) (9)** – Essential Energy does not have any related parties. All contracts Essential Energy has in place for the delivery of operating expenditure services are at arms' length from unrelated third parties. > **6.5.6 (e) (9A)** – Our operating expenditure forecast does not include any expenditure that should be more appropriately classed as a contingent project. > **6.5.6 (e) (10)** – Non-network alternatives are considered for our projects where appropriate. Further details can be found in supporting document 12.1.9 Network Strategy: Demand Management Strategy (Section 6 - Strategy) and supporting document 12.1.8 Network Strategy: Distribution Growth (Section 4.5 - Demand Management). > **6.5.6 (e) (11)** Presently, Essential Energy does not have any final RIT-D project assessment reports for the next regulatory period. These reports will be produced closer to the decision date. > **6.5.6 (e) (12)** There are no other factors that the AER has requested.
10.2 (a)	Provide: the quantum of non-recurrent opex for each year of the *forthcoming regulatory control period;* and	RIN Table 2.16.1 and 2.17.1 provides the quantum of non-recurrent operating expenditure relative to the base year. Further information about our operating and expenditure plans and why they are efficient can be found in Attachment 11.3 to our regulatory proposal - Standard Control Opex Approach and the Benchmarking chapter in the Regulatory Proposal.
10.2 (b)	explanation of the driver of each non-recurrent opex;	Refer to Section 4 of our Attachment 11.3 to our regulatory proposal - Standard Control Opex Approach.

RIN section	Requirement	Essential Energy Response
10.3	If Essential Energy used a revealed cost base year approach to develop its total forecast opex proposal, provide:	Note only
10.3 (a)	in Microsoft Excel format, reconciliation (including all calculations and formulae) of Essential Energy's forecast total opex proposal to forecast standard control services opex and dual function assets opex by opex driver in Workbook 1 – Regulatory determination, regulatory template 2.16, tables 2.16.1 and 2.16.3;	Total operating expenditure for 2016/17 reconciles with Table 2.1.1 of the CA RIN and forecast total operating expenditure in Table 2.16.1 reconciles with the total operating expenditure in Table 2.1.2. and 2.11.3. Attachment R4 to this RIN response provides the reconciliation.
10.3 (b)	the base year Essential Energy used; and	2017/18 is the base year used for opex forecasting purposes.
10.3 (c)	explanation and justification for why that *base year* represents efficient and recurrent costs;	The benchmarking and operating expenditure chapters of our regulatory proposal explains justifies our base year opex as being efficient. Further explanation and justification can be found at: > Attachment 11.3 to our regulatory proposal - Standard Control Opex Approach > Attachment 13.2 to our regulatory proposal – Economic benchmarking analysis (Frontier Economics)
10.4	If Essential Energy did not use a revealed cost base year approach to develop its total forecast opex, provide:	Clause 10.4 is not applicable because a revealed cost base approach to forecasting opex was used by Essential Energy. For more information refer to Attachment 11.3 to our regulatory proposal - Standard Control Opex Approach
10.4 (a)	forecast expenditure by opex category in Workbook 1 – Regulatory determination, regulatory template 2.16 for standard control services opex and dual function asset opex in tables 2.16.2 and 2.16.4;	
10.4 (b)	in Microsoft Excel format, reconciliation (including all calculations and formulae) of Essential Energy's total forecast opex proposal to forecast standard control services opex and dual function assets opex by opex category in Workbook 1 – Regulatory determination, regulatory template 2.16, tables 2.16.2 and 2.16.4;	
10.4 (c)	explanation of major drivers for the increases and decreases in expenditure by *opex category* in the *forthcoming regulatory control period* compared to actual historical expenditure;	
10.4 (d)	explanation and justification for:	
10.4 (d) i	whether Essential Energy considers there is a year of historic opex that represents efficient and recurrent costs; or	
10.4 (d) ii	why Essential Energy considers no year of historic opex represents efficient and recurrent costs.	

RIN section	Requirement	Essential Energy Response
10.5	Provide the amount of total forecast opex attributable to output growth changes for standard control services opex and dual function assets opex in Workbook 1 – Regulatory determination, regulatory template 2.16, tables 2.16.1 and 2.16.3.	Refer to RIN Template 2.16.1. Attachment R11 to this RIN response contains the Opex Rate of Change model. provides further information. Essential Energy does not have any dual function assets.
10.6 (a)	Provide the output growth drivers Essential Energy used to develop the amount of total forecast opex attributable to output growth changes;	Essential Energy has adopted the approach used in the AER's operating expenditure model to develop the output growth rate. Attachment R11 to this RIN response contains the Opex Rate of Change model. This model uses a weighted average growth rate based on customer numbers, circuit length, and ratcheted maximum demand to derive output growth forecasts. Increases to operating expenditure relating to output growth are offset by assumed efficiency savings over and above the cost reductions set out in our regulatory proposal for standard control services.
10.6 (b)	any economies of scale factors applied to the growth drivers;	
10.6 (c)	evidence that the growth drivers explain cost changes due to output growth; and	
10.6 (d)	if Essential Energy applied any composite multiple output growth drivers:	
10.6 (d) i	the inputs for each composite multiple output growth driver; and	
10.6 (d) ii	the weightings for each input;	
10.7	Provide an explanation of how, in developing the amount of total forecast opex attributable to output growth changes, Essential Energy:	
10.7 (a)	applied the output growth drivers; and	
10.7 (b)	accounted for economies of scale.	
10.8	Provide the amount of total forecast opex attributable to changes in the price of labour and materials for standard control services opex and dual function assets opex in Workbook 1 – Regulatory determination, regulatory template 2.16, tables 2.16.1 and 2.16.3.	RIN Table 2.16.1 highlights the value of assumed price and output growth applied to Essential Energy's forecast operating expenditure. These amounts have been developed using an excerpt of the AER's operating expenditure model which can be found at Attachment R11 – Opex Rate of Change model - to this RIN response. This approach uses forecast labour and non-labour rate increases and an estimate of the amount of labour applicable to operating expenditure. An average of EGWWS index and CEG forecasts (refer to supporting document 9.2.1) has been used to calculate an average labour rate increase. Essential Energy has used the most recent three years' average of direct in-house labour operating expenditure as a portion of total reported operating expenditure in calculating the portion of opex attributable to labour. This provides an estimate of about 70%, which is consistent with business expectations. The price growth rate associated with forecast labour rates is shown in Table 2.14.2. Increases to operating expenditure relating to price growth are offset by assumed efficiency savings over and above the cost reductions set out in our regulatory proposal for standard control services.

RIN section	Requirement	Essential Energy Response
10.9	Provide an explanation of:	Applying the AER's operating expenditure model does not include forecast productivity growth. However, we have assumed that both the forecast price and output growth amounts calculated using the rates in Table 2.14.2 will be offset by productivity (efficiency) improvements over and above the cost reductions set out in our regulatory proposal for standard control services. This productivity improvement is shown as an offsetting amount to the price and output growth lines in Table 2.16.1 of the RIN templates.
10.9 (a)	how, in developing the amount of total forecast opex attributable to changes in the price of labour and materials, Essential Energy applied the real price measures in Workbook 1 – regulatory determination, regulatory template 2.14; and	
10.9 (b)	whether Essential Energy's labour price measure compensates for any form of labour productivity change.	
10.10	Productivity Changes: Provide the amount of total forecast opex attributable to changes in productivity for standard control services opex and dual function assets opex in Workbook 1 – Regulatory determination, regulatory template 2.16, tables 2.16.1 and 2.16.3.	
10.11	Provide, in percentage year on year terms, the productivity measure that Essential Energy used to develop the amount of total forecast opex attributable to changes in productivity;	The productivity percentage is shown in Attachment 11.3 to our regulatory proposal - Standard Control Opex Approach.
10.12	Provide an explanation of:	Our operating expenditure forecasts are based on the assumption that any underlying price and output growth would be offset by productivity (efficiency) improvements over and above the cost reductions set out in our regulatory proposal for standard control services. As such, the productivity measure is the negative sum of the cumulative value of the price and output growth measures. This means the productivity measure does not include any historic trend of cost increases due to changes in regulatory obligations or requirements or industry best practice per se. The productivity measure applied to our operating expenditure forecasts fully compensates for any labour price measure applied. Further efficiency improvements are forecast to result from step changes, as detailed in section 11. For more information please refer to Attachment 11.3 to our regulatory proposal - Standard Control Opex Approach.
10.12 (a)	how, in developing the amount of total forecast opex attributable to changes in productivity, Essential Energy applied the productivity measure in paragraph 10.11;	
10.12 (b)	whether Essential Energy's forecast productivity changes capture the historic trend of cost increases due to changes in regulatory obligations or requirements and industry best practice; and	
10.12 (c)	whether Essential Energy's productivity measure includes productivity change compensated for by the labour price measure used by Essential Energy to forecast the change in the price of labour.	

11. Step changes

RIN section	Requirement	Essential Energy Response
11.1	Provide the amount of total forecast opex attributable to opex step changes for standard control services opex and dual function assets opex in Workbook 1 – Regulatory determination, regulatory template 2.16, tables 2.16.1 and 2.16.3.	Table 2.17.1 shows the total amount of operating expenditure attributable to step changes. The total of this table reconciles to the step changes line in Table 2.16.1.
11.2	Provide an explanation of why Essential Energy considers:	Note only
11.2 (a)	the efficient costs of the step change are not provided by other components of Essential Energy's total forecast opex such as base opex, output growth changes, real price changes or productivity change;	Our forecast contains two step changes: one as a result of a change to accounting standards (property leases) and the other to achieve longer-term efficiency savings (strategic initiatives spend/benefits). Both of these are step changes down (i.e. they reduce our total opex forecast over the 2019-24 Regulatory Period). Note that the delivery of reduced opex from the strategic initiatives step change requires an increase in investment in the early part of the Regulatory period, namely in technology investment. However, the savings across the Regulatory period outweigh these investment costs and will have an ongoing downward impact on opex beyond the next Regulatory period. The strategic initiatives expenditure impacts direct opex and direct capex, but the resulting benefits necessarily impact capital and operating expenditure through the application of overheads. The forecast efficiencies embedded in our expenditure forecasts can not be achieved without the strategic initiatives expenditure. Essential Energy has demonstrated how it will achieve the objectives and criteria in clause 6.5.6 of the NER as shown in responses to section 10.1(b)i and 10.1(b)ii in this document. Further information can be found in the delivering value and operating expenditure chapter of our Regulatory Proposal and in Attachment 11.3 to our regulatory proposal - Standard Control Opex Approach.
11.2 (b)	the total forecast opex will not allow Essential Energy to achieve the objectives in clause 6.5.6(a) of the NER unless the step change is included; and	
11.2 (c)	the total forecast opex will not reasonably reflect the criteria in clause 6.5.6(c) of the NER unless the *step change* is included.	
11.3	For all step changes in forecast expenditure provide:	See Table 2.17. Further information can be found in and Attachment 11.3 to our regulatory proposal - Standard Control Opex Approach.
11.3 (a)	In Workbook 1 – regulatory determination, regulatory template 2.17 the quantum of the step changes:	
11.3 (a) i.	forecasts for each year of the *forthcoming regulatory control period; and*	
11.3 (a) ii.	expected to be incurred, in the *current regulatory control period*;	
11.3 (b)	a description of the *step change.*	

RIN section	Requirement	Essential Energy Response
11.4	For each step change listed in response to paragraph 11.3, provide an explanation of:	Note only
11.4 (a)	when the change occurred, or is expected to occur;	The reduction in property lease expenditure step change takes effect 1 July 2019. The Strategic Initiatives costs and benefits occur as per table 2.17.1. There are a large number of individual initiatives in this program. The costs and benefits of these initiatives will progress through this regulatory period and the next. Further information can be found in the delivering value and operating expenditure chapter of our regulatory proposal and Attachment 11.3 to our regulatory proposal - Standard Control Opex Approach.
11.4 (b)	what the driver of the s*tep change* is;	The Property Leases step change is due to a change in accounting standard AASB 16. The Strategic initiatives step change is driven by the need to create further efficiencies and cost reductions throughout the business to limit price increases in the next regulatory period and put downward pressure on prices in the long term. Further information can be found in the delivering value and operating expenditure chapter of our regulatory proposal and Attachment 11.3 to our regulatory proposal - Standard Control Opex Approach.
11.4 (c)	how the driver has changed or will change (for example, revised legislation may lead to a change in a *regulatory obligation or requirement);* and	As above.
11.4 (d)	whether the s*tep change* is recurrent in nature;	The Property Leases step change is recurrent (permanent). The Strategic initiatives step change will require a temporary increase in operating and capital expenditure implementation costs in the earlier years that will taper off and give way to efficiency savings from 2021-22 onwards. The efficiency savings delivered by the initiatives are expected to be recurrent.

RIN section	Requirement	Essential Energy Response
11.5	For each step change listed in response to paragraph 11.3, provide justification for when, and how, the step change affected, or is expected to affect:	The impact on total operating expenditure is shown in Table 2.17.1 The impact on total capital expenditure is shown in Table 2.17.2 The reduction in property lease expenditure will occur on 1 July 2019. The property lease step change will impact on total opex and total capex. Currently, opex lease costs form part of our overhead pool which then get allocated across both total opex and total capex as part of our overhead allocation process. Under the accounting change these costs will now be treated as capex and then expensed as depreciation and interest. Note that there will be a large lump sum adjustment to property capex in the first year of the change as all leases are moved into capex, with smaller annual capex amounts ongoing. As outlined in 11.4, the strategic initiative expenditure/benefits are expected to take place throughout each financial year as the spend is incurred and benefits are realised. The savings achieved from 2012 through to today have been delivered mainly through significant employee reduction and cash containment initiatives. Additional savings will be much more difficult to achieve and require significant technology investments to realise. The complexity of these technology investments, with individual investments impacting on multiple cost categories, mean that it is difficult to forecast cost category impacts accurately. For this reason, the savings have been allocated to specific cost categories where possible (i.e. vegetation management) or to overheads where it is difficult to accurately estimate cost category impacts. Our overhead allocation process would then allocate these savings across both total opex and total capex. Actual savings will appear in their detailed cost category as they are achieved.
11.5 (a)	the relevant *opex category;*	
11.5 (b)	the relevant *capex category;*	
11.5 (c)	total opex; and	
11.5 (d)	total capex;	
11.6	For each step change listed in response to paragraph 11.3, provide the process undertaken by Essential Energy to identify and quantify the step change; provide cost benefit analysis that demonstrates (how) Essential Energy proposes to address the Step change in a prudent and efficient manner, including:	For the property lease step change, we considered the impact of the change in accounting standard (AASB 16) relating to leases which is required to be adopted effective 1 July 2019. Under AASB 16 the lease payments are no longer treated as operating expenses but the discounted value of expected lease payments over the lease term (including options expected to be take up) are capitalised and then expensed as depreciation and interest. Accordingly, no property lease costs are included in Opex from 1 July 2019, which represents a change from the previous treatment. The change in the accounting standard is mandatory and doing nothing is not an option. Refer to supporting document 12.1.20 – Asset Capitalisation policy draft for 1/7/2019 onwards, for further information. Essential Energy considers the strategic initiatives step change is critical to improving affordability of electricity services. The savings achieved from 2012 through to today have been delivered mainly through significant employee reductions and cash containment initiatives. Additional savings will be much more difficult to achieve and will require significant investments in technology in order to transform the business. Doing nothing would result in savings not being realised and would place upward pressure on prices for customers. More information can be found at: > Delivering Value and Operating Expenditure chapters of our Regulatory Proposal > Attachment 11.3 to our regulatory proposal - Standard Control Opex Approach. > Supporting document 12.1.16 – Information Technology business plan
11.6 (a)	the timing of the *step change;* and	
11.6 (b)	if Essential Energy considered a ‘do nothing’ option, evidence of how Essential Energy assessed the risks of this option compared with other options;	

RIN section	Requirement	Essential Energy Response
11.7	For each step change listed in response to paragraph 11.3, where the step change is due to a change in a regulatory obligation or requirement provide:	The capitalisation of property leases (and the associated reduction in lease operating expenditure) is the result of a change in accounting standards (AASB 16) as noted above. The Strategic Initiative step change is not related to a change in a regulatory obligations or requirements. These are required in order to drive further efficiencies and cost reductions in the business.
11.7 (a)	relevant variations or exemptions granted to Essential Energy during the previous regulatory control period or the current regulatory control period;	
11.7 (b)	any relevant compliance audits Essential Energy conducted during the previous regulatory control period or the current regulatory control period;	
11.8	For each step change listed in response to paragraph 11.7, provide, with reference to specific clauses of the relevant legislative instrument(s), the:	
11.8 (a)	previous regulatory obligation or requirement; and	
11.8 (b)	how the changed regulatory obligation or requirement is driving the *step change.*	
11.9	**Category Specific Opex**: Provide the amount of total forecast opex attributable to category specific opex in Workbook 1 – Regulatory determination, regulatory template 2.17, table 2.17.5. The amount of total opex attributable to category specific opex must correspond with the category specific opex reported in Workbook 1 – Regulatory determination, regulatory template 2.16, table 2.16.1.	The total forecast operating expenditure attributable to category-specific operating expenditure is provided in Table 2.17.5. The amount of total operating expenditure attributable to category-specific operating expenditure corresponds with the category-specific operating expenditure reported in Table 2.16.1.

Economic benchmarking reporting

12. Economic benchmarking

RIN section	Requirement	Essential Energy Response
12.1	Complete the Workbook 1 – regulatory determination, regulatory templates (3.1 to 3.7) in accordance with:	EB section in Workbook 1 completed per instructions.
12.1 (a)	the ‘Economic Benchmarking RIN for distribution network service providers – Instructions and Definitions’ issued to Essential Energy on 28 November 2013, chapters 2 to 9;	
12.1 (b)	(b) paragraphs 12.2 to 12.10.	
12.2	The forecast revenue groupings in Workbook 1 – Regulatory determination, regulatory templates 3.1, tables 3.1.1 and 3.1.2 may be developed by trending forward actual historical revenue groupings in previous regulatory years. However:	Due to timing issues in the finalisation of regulatory proposal inputs, there are some immaterial differences between Tables 3.1.1 and 3.1.2 and the forecast revenues proposed in our regulatory proposal and attachment 9.1 to our regulatory proposal – post tax revenue model (PTRM). The immaterial difference in the FY19 Revenue data is due to rounding errors and the application of STPIS adjustments in the over recovery calculations in the remittal. These have been discussed with AER staff and were raised in our response to the AER’s draft decision.
12.2 (a)	Total revenues must equal the total forecast revenues proposed by Essential Energy in its revenue proposal, and	
12.2 (b)	Revenue groupings must reflect Essential Energy's forecast demand for its services in the forthcoming regulatory control period in its regulatory proposal.	
12.3	Information provided in Workbook 1 – Regulatory determination, regulatory templates 3.2, tables 3.2.1 and 3.2.2 must reflect Essential Energy’s cost allocation method.	Tables 3.1.1 and 3.1.2 revenues have been developed in accordance with Essential Energy’s cost allocation method (CAM) – Attachment 11.1 to the Regulatory Proposal.
12.4	RAB asset financial data in the Workbook 1 – Regulatory determination, regulatory template 3.3 must reconcile to that in Essential Energy’s regulatory proposal PTRM and RFM.	The data in template 3.3 reconciles to our RFM (see Attachment 9.2 to the Regulatory Proposal) and PTRM (see Attachment 9.1 to the Regulatory Proposal).
12.5	The definition of a tree must be applied when completing the variables “Average number of trees per urban and CBD vegetation maintenance span” (DOEF0208) and “Average number of trees per rural vegetation maintenance span” (DOEF0209)	The definition of a tree has been applied as per RIN instructions.

RIN section	Requirement	Essential Energy Response
12.6	In calculating responses to the variables DOEF0202 to DOEF0205, spans in the network service area where Essential Energy is not responsible for the vegetation management associated with the span are not to be counted.	In calculating responses to the variables DOEF0202 to DOEF0205, spans in the network service area where Essential Energy is not responsible for the vegetation management associated with the span were not counted. This is limited to private HV mains spans.
12.7	"Total number of spans" (DOEF0205) does not include service line spans.	"Total number of spans" (DOEF0205) does not include service line spans.
12.8	Essential Energy must report the route line length of feeders classified as either short rural or long rural divided by the total route feeder line length (this is the total feeder route line length for all CBD, urban, short rural and long rural feeders) against "Rural proportion" (DOEF0201).	"Rural proportion" (DOEF0301) calculated as per stated methodology.
12.9	For the purposes of calculating the "*Route line length*" variable (DOEF0301) or *other variables* measured in terms of *route line length*:	Note only.
12.9 (a)	the length of service lines are not to be counted	Essential Energy has calculated the "Route line length" variable (DOEF0301), and other variables measured in terms of route line length, as per these items
12.9 (b)	the length of a span that shares multiple voltage levels is only to be counted once	
12.9 (c)	the lengths of two sets of lines that run on different sets of poles (or towers) but share the same easement are counted separately	
12.10	All forecast variables in the Workbook 1 – regulatory determination, regulatory templates (3.1 to 3.7) must align with those in Essential Energy's regulatory proposal. For the avoidance of doubt this includes forecast:	Reconciliation of RINs with Proposal documents completed
12.10 (a)	opex and capex;	The Operating expenditure and capital expenditure in the RIN templates reconcile with the Regulatory Proposal and Attachment 9.1 to our regulatory proposal – PTRM and Attachment 9.2 to our regulatory proposals – RFM.
12.10 (b)	*maximum demand,* customer numbers, energy delivery;	Maximum demand, customer numbers and energy in the RIN templates reconciles with regulatory proposal and Attachment 9.1 to our regulatory proposal.
12.10 (c)	revenues;	Revenue in the RIN templates reconciles with the Regulatory Proposal and Attachment 9.1 to our regulatory proposal – PTRM.
12.10 (d)	quality of services variables including SAIDI and SAIFI; and	Quality of service variables in the RINs reconcile with the Regulatory Proposal.
12.10 (e)	quantities of physical assets	Quantities of physical assets in the RINs reconcile with Regulatory Proposal.

Alternative control services reporting

13. Alternative control services

RIN section	Requirement	Essential Energy Response
13.1	13.1 The overheads relating to each alternative control service listed in paragraph 13.2 must be disclosed	The overheads relating to each alternative control service model are set out in: > Attachment 17.2 to our regulatory proposal – metering model > Attachment 17.5 to our regulatory proposal – public lighting model > Attachment 17.7 to our regulatory proposal – ancillary network services model
13.2	Provide a list of all of the alternative control services that Essential Energy intends to provide to customers and levy charges for in the forthcoming regulatory control period.	Attachment 8.1 to our regulatory proposal – classification of services provides a list of alternative control services proposed for the 2019-24 regulatory period 2019-24 Indicative pricing schedules for each alternative control service can be found at: > Attachment 2 to our TSS - Indicative Ancillary Network Services Pricing Schedule > Attachment 3 to our TSS - Indicative Metering Services Pricing Schedule > Attachment 4 to our TSS - Indicative Public Lighting Pricing Schedule
13.3	Provide a definition of each alternative control service listed in paragraphs 14, 15 and 16.	The framework and approach and alternative control services chapter provides and overview of our alternative control services. Attachment 8.1 to our regulatory proposal – classification of services provides a definition of alternative control services proposed for the 2019-24 regulatory period. Further information is also provided in: > Attachment 2 to our TSS - Indicative Ancillary Network Services Pricing Schedule > Attachment 3 to our TSS - Indicative Metering Services Pricing Schedule > Attachment 4 to our TSS - Indicative Public Lighting Pricing Schedule
13.4	For each *alternative control service* listed in paragraphs 14, 15 and 16, specify the charges applicable during each year of the *current regulatory control period.* Also include proposed charges for each year of the *forthcoming regulatory control period.*	The charges applicable for each year of the current regulatory period and the forthcoming regulatory period can be found at: > 17.7 ANS Model - Current and Proposed Fees ACS - 20180430 – Public > Attachment 17.2 to our regulatory proposal – metering model > Attachment 17.5 to our regulatory proposal – public lighting model

RIN section	Requirement	Essential Energy Response
13.5	For each alternative control service listed in paragraphs 14, 15 and 16, specify the total revenue earned by Essential Energy in each year of the current regulatory control period and forecast to be earned in the forthcoming regulatory control period.	Revenue for the current 2014-19 regulatory period and Forecast revenue for the 2019-24 regulatory period can be found in: • Attachment 17.1 to our regulatory proposal – Type 5 and 6 metering services proposal • Attachment 17.4 to our regulatory proposal – Public lighting proposal • Attachment 17.6 to our regulatory proposal – Ancillary Network Services Proposal
13.6	For each *alternative control service* listed in paragraphs 14, 15 and 16, provide the labour rate(s) used to calculate the charges for the *current* and *forthcoming regulatory control periods:*	The labour rates and classification level used to calculate charges relating to each alternative control service model are set out in: • Attachment 17.2 to our regulatory proposal – metering model • Attachment 17.5 to our regulatory proposal – public lighting model • Attachment 17.7 to our regulatory proposal – ancillary network services model The labour rates for the current and forthcoming regulatory periods are provided in the models, apart from 2016/17. Labour rates increased by 2.5% on 1 July 2016.
13.6 (a)	Specify the *labour classification level* used to provide the services e.g. outsourced or internally provided and labourer type.	
13.6 (b)	List all *direct costs*, and their quantum, in the make-up of the labour rate(s).	
13.7	List each material category (e.g. meters, poles, brackets) required for the provision of *each alternative control service* listed in the response to paragraphs 14, 15 and 16.	Materials information used to calculate charges relating to each alternative control service model are set out in: • Attachment 17.2 to our regulatory proposal – metering model • Attachment 17.5 to our regulatory proposal – public lighting model • Attachment 17.7 to our regulatory proposal – ancillary network services model
13.7 (a)	Provide a description of each material category.	
13.7 (b)	Provide the average unit costs for each material category.	
13.7 (c)	List all *direct costs* included in the unit costs.	
13.7 (d)	Specify the calculation of the quantum of *direct materials costs* included in the unit cost of materials.	

14. Fee based and quoted alternative control services

RIN section	Requirement	Essential Energy Response
14.1	Provide a description of each fee based and quoted service, explaining the purpose of the service and list the activities which comprise each service. The list of fee based and quoted services should be consistent with those services listed in Essential Energy's annual pricing proposals.	The framework and approach and alternative control services chapters of our regulatory proposal provide an overview of these services. Attachment 8.1 to our regulatory proposal – classification of services provides a definition of alternative control services proposed for the 2019-24 regulatory period. Detailed information on fee based and quoted services is provided in: > Attachment 2 to our TSS - Indicative Ancillary Network Services Pricing Schedule > Attachment 17.6 to our regulatory proposal – Ancillary Network Services Proposal > Attachment 17.7 to our regulatory proposal – Ancillary network services model The charges applicable for each year of the current regulatory period and the forthcoming regulatory period can be found at: > 17.7 ANS Model - Current and Proposed Fees ACS - 20180430 – Public
14.1 (a)	Specify if the charges are for *fee based* and/or *quoted alternative control services;*	
14.1 (b)	Explain the reasons for the different charge with reference to the costs incurred;	
14.1 (c)	Explain the method used to set the different charge; and	
14.1 (d)	Provide the calculations underpinning the different charge.	
14.2	Identify the tasks involved in providing the service in Workbook 1 – regulatory determination, regulatory templates 4.3 and 4.4	
14.2 (a)	Map the class of labour required to provide the service listed in *regulatory templates* 4.3 and 4.4.	
14.2 (b)	The number of workers required to undertake the task and deliver the service.	
14.2 (c)	The average time required to complete the task and deliver the service.	
14.3	If materials are required to provide the service, specify each material category.	
14.4	Provide all current and proposed charges for each *fee based* and *quoted alternative control service* in the current and *forthcoming regulatory control periods.*	

15. Metering alternative control services

RIN section	Requirement	Essential Energy Response
15.1	For metering alternative control services for the current regulatory control period and the forthcoming regulatory control period, provide details of the:	The framework and approach and alternative control services chapters of our regulatory proposal provide an overview of these services. Attachment 8.1 to our regulatory proposal – classification of services provides a definition of alternative control services proposed for the 2019-24 regulatory period. Detailed information on metering services is provided in: > Attachment 3 to our TSS - Indicative Metering Services Pricing Schedule > Attachment 17.1 to our regulatory proposal – Type 5 and 6 Metering Services Proposal > Attachment 17.2 to our regulatory proposal – Metering Model > Attachment 17.3 to our regulatory proposal – Metering PTRM > Supporting document 17.1.1 – Type 5 and 6 metering services AMP The charges applicable for each year of the current regulatory period and the forthcoming regulatory period can be found at: > Attachment 17.2 to our regulatory proposal – metering model
15.1 (a)	*Direct materials* and direct labour costs;	
15.1 (b)	Installation costs;	
15.1 (c)	Meter purchase costs;	
15.1 (d)	Volumes of work;	
15.1 (e)	Other costs associated with providing metering services;	
15.1 (f)	Type of meters installed and forecast to be installed, separately for new meters and for replacement meters;	
15.1 (g)	The volume of meters by type set out in (f) and the revenue earned and forecast to be earned by each meter type; and	
15.1 (h)	The total operating and *maintenance* costs incurred, and forecast to be incurred, for metering services.	
15.2	For metering works, for each year of the *current regulatory control period* and forecasts for the *forthcoming regulatory control period,* provide a description of:	
15.2 (a)	The type of work undertaken (e.g. *meter reconfiguration*, *special meter read*) including a description of the activities undertaken to provide the service;	
15.2 (b)	The *labour costs* involved in providing the service, including any *overheads;*	
15.2 (c)	Any materials costs involved in providing the service;	
15.2 (d)	The number (volume) of services provided and associated assumptions on which the volume of service was derived or estimated;	
15.2 (e)	The charge per service; and	
15.2 (f)	The revenue earned by each service.	

RIN section	Requirement	Essential Energy Response
15.3	For metering alternative control services, specify the number of customers in each year of the *current regulatory control period*, and forecasts for the *forthcoming regulatory control period.*	

16. Public lighting alternative control services

RIN section	Requirement	Essential Energy Response
16.1	Specify which items are capex and operational expenditure for each year of the *current regulatory control period* and forecasts for the *forthcoming regulatory control period.*	The framework and approach and alternative control services chapters of our regulatory proposal provide an overview of these services. Attachment 8.1 to our regulatory proposal – classification of services provides a definition of alternative control services proposed for the 2019-24 regulatory period.
16.2	Provide unit costs for the current regulatory control period and forecast for the forthcoming regulatory control period for:	Detailed information on public lighting is provided in: > Attachment 4 to our TSS - Indicative Public Lighting Pricing Schedule > Attachment 17.4 to our regulatory proposal – Public Lighting Services Proposal > Attachment 17.5 to our regulatory proposal – Public Lighting Model > Supporting document 17.4.1 – Public lighting AMP The charges applicable for each year of the current regulatory period and the forthcoming regulatory period can be found at: > Attachment 17.4 to our regulatory proposal – public lighting model
16.2 (a)	Luminaires;	
16.2 (b)	Dedicated street lighting poles;	
16.2 (c)	Brackets;	
16.2 (d)	Lamps;	
16.2 (e)	Photoelectric cells;	
16.2 (f)	Labour rate (per hour);	
16.2 (g)	Miscellaneous materials.	
16.3	Provide the depreciation period in years for each type of luminaire.	
16.4	Provide the bulk change cycle in years for lamps and photoelectric cells.	
16.5	Provide details of the average replacement age of each type of luminaire.	
16.6	Provide the number of luminaries, by type, for the current and forthcoming regulatory control periods	
16.7	Provide the number of luminaires, poles and brackets replaced by year, for the current and *forthcoming regulatory control periods.*	
16.8	Provide details, including assumptions used, for any other costs that are incurred for the provision of *public lighting services.*	
16.9	Provide models and/or modelling that underpins proposed charges for the forthcoming regulatory control period and the reasons for the assumptions behind those forecasts.	

RIN section	Requirement	Essential Energy Response
16.10	For public lighting alternative control services, specify the number of customers in each year of the current regulatory control period, and forecasts for the forthcoming regulatory control period.	

17. Demand and connection forecasts

RIN section	Requirement	Essential Energy Response
17.1	Provide and describe the methodology used to prepare the following forecasts for the *forthcoming regulatory control period:*	Note only
17.1 (a)	*maximum demand*; and	Essential Energy engaged NIEIR to develop our maximum demand forecast. The methodology is outlined in the energy and demand forecasts chapter of our Regulatory Proposal. Further detailed information can be found in Attachment 14.1 to our regulatory proposal — Electrical energy and customer number projections for Essential Energy in New South Wales to 2029-30 (National Institute of Economic and Industry Research).
17.1 (b)	number of new *connections.*	
17.2	Provide:	Note only
17.2 (a)	the model(s) Essential Energy used to forecast new connections and maximum demand;	Essential Energy engaged NIEIR to develop our new customer connection and demand forecast. The methodology is outlined in Attachment 14.1 to our regulatory proposal – Electrical energy and customer number projections for Essential Energy in New South Wales to 2029-30 (National Institute of Economic and Industry Research). The maximum demand at the network level and some TNI values were derived by NIEIR. The maximum demand at zone substation and, where required, information for the TNI were derived by Essential Energy using AEMO's Connection Point Forecasting Methodology.
17.2 (b)	where Essential Energy's approach to weather correction has changed, provide historically consistent weather corrected maximum demand data, as per the format in Workbook 1 – regulatory determination, regulatory templates 3.4 and 5.4 using Essential Energy's current approach. If any of this data is unavailable, explain why;	The weather-corrected data was calculated for the vast majority of sub-transmission and zone substations based on the nationally consistent methodology (Connection Point Forecasting, AEMO, 2013) using regression of daily demands and historical local temperature data.
17.2 (c)	for new connections, volume expenditure data requested in Workbook 1 – regulatory determination, regulatory template 2.5; and	The rate of change from NIEIR forecasts (Attachment 14.1 to our regulatory proposal – Electrical energy and customer number projections for Essential Energy in New South Wales to 2029-30 (National Institute of Economic and Industry Research) of net connections was used to inform forecast of gross connections (Table 2.5).
17.2 (d)	any supporting information or calculations that illustrate how information extracted from Essential Energy's forecasting model(s) reconciles to, and explains any differences from, information provided in regulatory templates 2.5, 3.4 and 5.4.	The data from Essential Energy's maximum demand forecasting models was used to populate Tables 3.4 and 5.4. Further detail can be provided on a case by case basis. However, it is not practical to provide all forecasting models. There are approximately 400 forecasting models totalling 15-20 GB. High level numbers of connections provided in table 2.5 are derived as per question 17.2c), connections are not used directly in the derivation of tables 3.4 and 5.4. with the exception of a small number of large spot loads relating to real estate developments. Historic trends in load growth caused by increasing connections will be indirectly included in forecasts.

RIN section	Requirement	Essential Energy Response
17.3	For each of the methodologies provided and described in response to paragraph 17.1, and, where relevant, data requested under 17.2(b) and 17.2(c) explain or provide (as appropriate):	Note only
17.3 (a)	the models used;	Essential Energy forecasts using time series, following AEMO's Connection Point Forecasting Methodology. Further detail can be provided on a case by case basis. However, it is not practical to provide all forecasting models. There are approximately 400 forecasting models totalling 15-20 GB.
17.3(b)	a global (top-down) and spatial (bottom-up) demand forecast;	We used a spatial (bottom-up) process for augmentation purposes and a top-down forecast for pricing purposes.
17.3 (c)	the inputs and assumptions used in the models (including in relation to economic growth, *connections* numbers and policy changes and provide any associated models or data relevant to justifying these inputs and assumptions);	NIEIR’s network-wide forecast incorporates economic growth and other factors. Refer to Attachment 14.1 to our regulatory proposal – Electrical energy and customer number projections for Essential Energy in New South Wales to 2029-30 (National Institute of Economic and Industry Research). Sub-transmission and zone substation forecasts were completed based on time series trends.
17.3 (d)	the weather correction methodology, how weather data has been used, and how Essential Energy's approach to weather correction has changed over time;	For the previous Reset RIN, Essential Energy did not provide weather-corrected data. We now use the AEMO methodology to weather-correct all TNI, sub-transmission and zone substation data. We intend to expand this to HV feeders in the future.
17.3 (e)	an outline of the treatment of *block loads, transfers* and *switching* within the forecasting process;	Historic block loads were removed or avoided (depending on the length of time series available) in the forecasting process. Load transfers and switching were cleaned out of the data before weather-correction where possible. Future block loads were added back into the forecasts as a step change.
17.3 (f)	each appliance model used, where used, or assumptions relating to average *customer* energy usage (by *customer* type);	Essential Energy has not used appliance models in developing spatial forecasts. For the global forecast, refer to Attachment 14.1 to our regulatory proposal – Electrical energy and customer number projections for Essential Energy in New South Wales to 2029-30 (National Institute of Economic and Industry Research).
17.3 (g)	how the forecasting methodology used is consistent with, and takes into account, historical observations (where appropriate), including any calibration processes undertaken within the model (specifically whether the load forecast is matched against actual historical load on the system and substations);	Demand forecasts were based on system demand data obtained since 2004 (where available). Historic block loads and changes in trend may deem earlier data less valuable as a predictor and we catered for this on a case by case basis.
17.3 (h)	how the resulting forecast data is consistent across forecasts provided for each network element identified in Workbook 1 – regulatory determination, regulatory template 5.4 and system wide forecasts;	Each zone substation in Table 5.4 was passed through the same forecasting method.

RIN section	Requirement	Essential Energy Response
17.3 (i)	how the forecasts resulting from these methods and assumptions have been used in determining the following:	Note only.
17.3 (i)	capex forecasts; and	We used the forecasts directly as a first pass analysis of zone substation constraints and in network models for sub-transmission constraints.
17.3 (ii)	operating and maintenance expenditure forecasts.	Essential Energy has invested in optimisation tools and intelligence to balance risk against investments for capital activities. These capital activities take into account the operational and maintenance trade-offs with a range of options analyses.
17.3 (j)	whether Essential Energy used the forecasting model(s) it used in the joint planning process for the purposes of its regulatory proposal;	Essential Energy's forecasting process and modelling is the same for joint planning as for internal use.
17.3 (k)	whether Essential Energy forecasts both coincident and non-coincident maximum demand at the feeder, connection point, sub-transmission substation and zone substation level, and how these forecasts reconcile with the system level forecasts (including how various assumptions that are allowed for at the system level relate to the network level forecasts);	Essential Energy only forecasts non-coincident maximum demand at the TNI, feeder, and sub-transmission and zone substation level.
17.3 (l)	whether Essential Energy records historic maximum demand in MW, MVA or both;	Essential Energy's historic maximum demand is recorded in many different values across various sites. MW and MVA are used where available.
17.3 (m)	the probability of exceedance that Essential Energy uses in network planning;	We operate a largely radial network. Constraints are identified using POE50 forecasts. A probabilistic examination of the value of the benefit of a project is used to determine the best option. This includes analysing load-sharing, non-network solutions etc.
17.3 (n)	the contingency planning process, in particular the process used to assess high system demand;	
17.3 (o)	how risk is managed across the *network*, particularly in relation to load sharing across *network* elements and non-network solutions to peak demand events;	
17.3 (p)	whether and how the maximum demand forecasts underlying the regulatory proposal reconcile with any demand information or related planning statements published by AEMO, as well as forecasts produced by any transmission network service providers connected to Essential Energy's network;	The maximum demand forecasts underpinning the Regulatory Proposal align with the annual connection point demand forecasts Essential Energy provides to Transmission Network Service Providers as a requirement of the NER and AEMO requests. We work closely with AEMO, sharing data and forecasts and providing advice regarding their connection point demand forecasts.
17.3 (q)	how the normal and emergency ratings are used in determining capacity for individual *zone substations* and *sub-transmission lines;*	Essential Energy uses a probabilistic analysis of normal and emergency ratings to evaluate capacity and constraint issues on individual zone substations and sub-transmission lines.

RIN section	Requirement	Essential Energy Response
17.3 (r)	where Essential Energy proposes to commence or continue a demand-related capex project or program during the forthcoming regulatory control period on a HV feeder:	Essential Energy's HV feeder program is largely reactive, so we have minimal information. Where information is known, it is listed in the Distribution Annual Planning Report, as required by the NER. Further information can be found in supporting document 12.1.8 – Distribution Growth strategy.
17.3 (r) i	for each feeder from the *zone substation* that is the connecting *zone substation* for the relevant *HV feeder,* and any other feeders that the relevant *HV feeder* can transfer load to or from:	
17.3 (r) i (A)	assumed future load transfers between feeders;	
17.3(r) i (B)	assumed feeder underlying load growth rates (exclusive of *transfers* and specific *customer* developments); and	
17.3 (r) i (C)	assumed *block loads,* and associated demand assumptions;	
17.3 (r) ii	existing *embedded generation* capacity, and associated assumptions on the impact on demand levels;	
17.3 (r) iii	assumed future *embedded generation* capacity, and associated assumptions on the impact on demand levels;	
17.3 (r) iv	existing non-network solutions, and the associated assumptions on the impact on demand levels;	
17.3 (r) v	assumed future non-network solutions, and associated assumptions on the impact on demand levels; and	
17.3 (r) vi	the diversity between feeders;	

RIN section	Requirement	Essential Energy Response
17.3 (s)	where Essential Energy proposes to commence or continue a demand-related capex project or program during the forthcoming regulatory control period on a zone substation (or relevant substations for a sub-transmission line):	Essential Energy's zone substation and sub-transmission projects are detailed in individual project reports provided with the Regulatory Proposal. Further information can be found at Supporting document 12.1.15a to 12.1.15f – Major Project Options Reports.
17.3 (s) i	assumed future load transfers between related *substations;*	
17.3 (s) ii	assumed underlying load growth rates (exclusive of *transfers* and specific *customer* developments);	
17.3 (s) iii	assumed specific *customer* developments, and associated demand assumptions;	
17.3 (s) iv	existing *embedded generation* capacity, and associated assumptions on the impact on demand levels;	
17.3 (s) v	assumed future *embedded generation* capacity, and associated assumptions on the impact on demand levels;	
17.3 (s) vi	existing non-network solutions, and the associated assumptions on the impact on demand levels;	
17.3 (s) vii	assumed future non-network solutions, and associated assumptions on the impact on demand levels; and	
17.3 (s) viii	diversity with related substations.	
17.4 (a)	Provide evidence that any independent verifier engaged by Essential Energy has examined the reasonableness of the method, processes and assumptions in determining the forecasts and has sufficiently capable expertise in undertaking a verification of forecasts; and	Forecasts are generated independently by NIEIR (Attachment 14.1 to our regulatory proposal – Electrical energy and customer number projections for Essential Energy in New South Wales to 2029-30 (National Institute of Economic and Industry Research).) and reviewed against Essential Energy's forecasts. We also complete forecasts for AEMO and Transgrid, which are both independently reviewed and questioned.
17.4 (b)	all documentation, analysis and models evidencing the results of the independent verification.	AEMO and Transgrid forecasts are available at the request of the forecast owner. For NIEIR forecasting methodology, refer to Attachment 14.1 to our regulatory proposal – Electrical energy and customer number projections for Essential Energy in New South Wales to 2029-30 (National Institute of Economic and Industry Research).

Incentive schemes and other reporting

18. Efficiency benefits sharing scheme

RIN section	Requirement	Essential Energy Response
18.1	For the purposes of applying the *efficiency benefit sharing scheme:*	In line with previous submissions, Essential Energy's proposed operating expenditure for the EBSS is the controllable operating expenditure amount from the PTRM, found at Attachment 9.1 to our regulatory proposal. We propose that the following list of cost categories be excluded from the calculations of efficiency gains or losses to ensure our performance against the operating expenditure benchmarks is not distorted. The proposed exclusions are also consistent with the AER's previous determinations on EBSS for other DNSPs, and the requirements of clause 6.5.8 of the Rules are better achieved by excluding these operating expenditure categories: > Debt-raising costs > Costs of any approved pass-through events and new regulatory obligations introduced after the ASR's 2015 Final Determination > Insurance and self-insurance costs > Superannuation costs for defined benefits fund members > Operating costs associated with projects funded under the DMIA mechanism > Operating costs associated with demand management (non-network) initiatives as they will not be forecast using a single-year revealed-cost approach. > Costs for any services that will not be classified as Standard Control Services in the 2024–29 Regulatory Period. > The impact of excluding these categories would be to adjust both the operating expenditure allowance and actual operating expenditure that would be subject to the EBSS when the AER determines the revenue decrement or increments in calculating the EBSS carryover for the 2024–29 Regulatory Period.
18.1(a)	identify all cost categories proposed to be excluded from the operation of the *efficiency benefit sharing scheme;*	
18.1(b)	explain for each cost category identified in the response to paragraph 18.1(a) the reasons for the proposed exclusion.	

19. Service target performance incentive scheme

RIN section	Requirement	Essential Energy Response
19.1	Provide Essential Energy's detailed methodology for calculating the following parameters used in the STPIS:	Attachment 8.2 to our regulatory proposal – service target performance incentive scheme (STPIS) approach paper provides our proposed methodology for calculating STPIS parameters.
19.1 (a)	the SAIDI, SAIFI and MAIFI targets for each supply reliability area;	
19.1 (b)	the customer service parameters and targets;	
19.1 (c)	daily SAIDI, SAIFI and MAIFI and customer service performance derived from the individual interruption data under paragraph 19.3	
19.1 (d)	the MED threshold derived from the daily SAIDI data	
19.1 (e)	The incentive rates to apply to each supply reliability area	
	Note: All calculations must be made in accordance with the STPIS and using data which complies with the STPIS definitions	Note only
19.2	If Essential Energy proposes adjustments to the STPIS targets away from those based upon raw historical data Essential Energy must provide, in respect of each adjustment:	No adjustments are proposed away from the historical data targets.
19.2 (a)	the reasons for the adjustment;	
19.2 (b)	the quantum of the adjustment, and the effect of the adjustment on the targets for each of the supply reliability areas; and	
19.2 (c)	the method, basis and empirical data used as justification for the adjustment.	
19.3	Provide the data required in regulatory templates Workbook 1 – regulatory determination, 6.1 and 6.2.	Workbook completed.

20. Proposed contingent projects

RIN section	Requirement	Essential Energy Response
20.1	For each contingent project proposed in the *regulatory proposal*, provide:	Essential Energy has no contingent projects for the forthcoming regulatory period.
20.1 (a)	a description of the proposed contingent project, including reasons why Essential Energy considers the project should be accepted as a contingent project for the forthcoming regulatory control period;	
20.1 (b)	the proposed contingent capex which Essential Energy considers is reasonably required for the purpose of undertaking the proposed contingent project;	
20.1 (c)	the methodology used for developing that forecast and the key assumptions that underlie it;	
20.1 (d)	information that demonstrates that the undertaking of the *proposed contingent project* is reasonably required to meet one or more of the objectives referred to in clause 6.6A.1(b)(1) of the NER;	
20.1 (e)	a demonstration that the proposed contingent capex for each proposed contingent project:	
20.1 (e) i	is not included (either in part of in whole) in Essential Energy's proposed total forecast capex for the forthcoming regulatory control period;	
20.1 (e) ii	reasonably reflects the capital expenditure criteria, taking into account the capex factors, in the context of the proposed contingent project; and	
20.1 (e) iii	exceeds either $30 million ($ nominal) or 5 per cent of Essential Energy's proposed annual revenue requirement for the first year of the forthcoming regulatory control period, whichever is larger amount.	
20.1 (f)	the proposed trigger events relating to the proposed contingent project.	
20.2	For each proposed *trigger event relating to the proposed contingent project* referred to in 20.1 (f) demonstrate:	

RIN section	Requirement	Essential Energy Response
20.2 (a)	the proposed *trigger event* is reasonably specific and capable of objective verification	
20.2 (b)	the occurrence of the proposed trigger event makes the undertaking of the proposed contingent project reasonably necessary in order to achieve any of the capex objectives;	
20.2 (c)	the proposed *trigger event* generates increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the *network* as a whole;	
20.2 (d)	the proposed *trigger event* is described in such terms that the occurrence of that event or condition is all that is required for the *distribution determination* to be amended under clause 6.6A.2 of the NER;	
20.2 (e)	the proposed trigger event is a condition or event, the occurrence of which is probable during forthcoming regulatory control period, but the inclusion of capex in relation to the proposed trigger event under clause 6.5.7 of the NER is not appropriate because:	
20.2 (e) i	it is not sufficiently certain that the event or condition will occur during the *forthcoming regulatory control period* or if it may occur after that *regulatory control period* or not at all; or	
20.2 (e) ii	the costs associated with the event or condition are not sufficiently certain.	
20.3	Provide a summary of Essential Energy's proposed contingent projects for the forthcoming regulatory control period, including the proposed contingent capex and trigger events for each proposed contingent project in the Workbook 1 – regulatory determination, regulatory template 7.2.	

21. Revenue for standard control services

RIN section	Requirement	Essential Energy Response
21.1	Provide Essential Energy's calculation of the unsmoothed and smoothed revenues for each year of the forthcoming regulatory control period using the AER's post-tax revenue model, which is to be submitted as part of Essential Energy's regulatory proposal.	Essential Energy has calculated smoothed and unsmoothed revenues for each year of the Regulatory Period using the AER's PTRM model. The Our Revenue Requirement chapter of our regulatory proposal and Attachment 9.1 to our regulatory proposal - PTRM Model provide the calculations.
21.2	Provide details of any departure from the AER's post-tax revenue model for the calculations referred to in paragraph 21.1 and the reasons for that departure.	There have been no departures from the AER's post-tax revenue model.

22. Indicative impact on annual electricity bills

RIN section	Requirement	Essential Energy Response
22.1	For the purposes of calculating the impact of Essential Energy's regulatory proposal on the annual electricity bill of typical residential and business customers in New South Wales, provide the data/information required in Workbook 1 – regulatory determination, regulatory template 7.6. Provide the data source for each input used for the calculation.	The Our Approach to Pricing chapter of our regulatory proposal and the 2019-24 TSS provides the impacts of Essential Energy's regulatory proposal on the annual bill of typical customers. Data sources are provided in Template 7.6, Indicative Bill Impact. We have used NIEIR's forecast MWh for the Energy Delivered (Attachment 14.1 to our regulatory proposal – Electrical energy and customer number projections for Essential Energy in New South Wales to 2029-30 (National Institute of Economic and Industry Research), as per Table 3.4.1. Revenue is sourced from the AER's draft decision for the remittal of the 2014-19 regulatory period.

23. Proposed Tariff Structure Statement

RIN section	Requirement	Essential Energy Response
23.1	Provide the model(s) used to calculate the long run marginal cost estimates in Essential Energy's proposed tariff structure statement provided in accordance with the requirements of clauses 6.18.1A(a)(5) and 6.18.5(f) of the NER.	Attachment 6 to our TSS – how we design our tariffs, sets out our methodology, assumptions and relationships for calculating the long run marginal cost. Attachment 6.1 to the TSS contains Essential Energy's long run marginal cost model.
23.2	Provide and describe the methodology and assumptions used to prepare the long run marginal cost estimates in paragraph 23.1.	
23.3	Describe the relationship between the expenditure, demand and other inputs (as appropriate) used in the model provided under paragraph 23.1 and the expenditure, demand and other forecasts (as appropriate) provided as part of the building block proposal for the forthcoming regulatory control period.	

Regulatory asset base and tax reporting

24. Regulatory asset base

RIN section	Requirement	Essential Energy Response
24.1	Provide Essential Energy's calculation of the regulatory asset base for the relevant distribution system in respect of standard control services for each regulatory year of current regulatory control period using the AER's roll forward model, which is to be submitted as part of the regulatory proposal.	An overview of the calculation can also be found in the Our Revenue Requirement chapter of the Regulatory Proposal. Attachment 9.2 to our regulatory proposal contains the Roll forward Model (RFM) which sets out the calculation of the regulated asset base.
24.2	Provide details of each departure from the underlying methods in the *AER*'s *roll forward model* and *post-tax revenue model* for the calculations referred to in 24.1 and the reasons for that departure.	There have been no departures from the underlying methods in the AER's RFM or PTRM. Refer to Attachment 9.2 to our regulatory proposal - RFM and Attachment 9.1 to our regulatory proposal - PTRM.
24.3	If the value of the regulatory asset base as at the start of the forthcoming regulatory control period is proposed to be adjusted because of changes to asset service classification, provide details including relevant supporting information used to calculate that adjustment value.	We do not propose to adjust the opening RAB at 1 July 2019 for any asset service classification changes.
24.4	Provide details of any departure in the allocation of actual capex, asset disposal and customer contribution values across asset classes in the roll forward model from those reported in the Annual Reporting RIN for the relevant regulatory years and the reasons for that departure.	There are no departures in the allocation of actual capital expenditure, asset disposal and customer contribution values in the RFM from those reported in the Annual Reporting RIN for any years.

25. Depreciation schedules

RIN section	Requirement	Essential Energy Response
25.1	Provide Essential Energy's calculation of the depreciation amounts for the relevant distribution system in respect of standard control services for each regulatory year of:	Depreciation amounts have been calculated using the AER's preferred method, as calculated in the RFM (refer to Attachment 9.2 of the regulatory proposal) and PTRM (refer to Attachment 9.1 of the regulatory proposal). These models include the split between the RAB indexation and straight-line depreciation amounts. The high-level total regulatory depreciation amounts are shown in the Our Revenue Requirement chapter of our Regulatory Proposal and the accompanying Appendix A – Our revenue requirement components.
25.1 (a)	the current regulatory control period using the AER's roll forward model, which is to be submitted as part of the regulatory proposal	
25.1 (b)	the forthcoming regulatory control period using the AER's post-tax revenue model, which is to be submitted as part of the regulatory proposal.	
25.2	Provide details of any departure from the underlying methods in the AER's roll forward model and post-tax revenue model for the calculations referred to in paragraph 25.1 and the reasons for that departure.	There has been no departure to the underlying methods in the AER's RFM or PTRM.
25.3	Identify any changes to standard asset lives for existing asset classes from the previous determination. Explain the reason(s) for each change and provide supporting information.	There are no proposed changes to standard asset lives for existing asset classes.
25.4	Identify any changes to new asset classes from the previous determination. Explain the reason(s) for using these new asset classes and provide supporting information on their proposed standard asset lives.	There is one new asset class: capitalised property leases. Its addition results from a change in accounting standards that begins on 1 January 2019 as discussed above in section 11 – step changes.
25.5	If any existing asset classes from the previous determination are proposed to be removed and their residual values to be reallocated to other asset classes, explain the reason(s) for the change and provide supporting information. This should include a demonstration of the materiality of the change on the forecast depreciation allowance.	There are no proposed removals of existing asset classes.
25.6	Describe the method used to depreciate existing asset classes as at 1 July 2019 (the start of the forthcoming regulatory control period) and provide supporting calculations, if the approach differs from that in the roll forward model.	Existing asset classes have been depreciated using the approach determined by the AER for our 2014-19 set-aside determination i.e. forecast capital expenditure. The approach does not differ from that in the RFM (refer to Attachment 9.2 of our regulatory proposal), so no additional supporting calculations/materials are required.

26. Corporate tax allowance

RIN section	Requirement	Essential Energy Response
26.1	Provide Essential Energy's calculation of the estimated cost of corporate income tax for the forthcoming regulatory control period using the AER's post-tax revenue model, which is to be submitted as part of the regulatory proposal.	Our calculation is consistent with that outlined in the AER's PTRM (refer to Attachment 8.1 of our regulatory proposal). In accordance with the NER, total tax expenses are reduced by the value of imputation credits. We have adopted the AER's preferred value of 0.4 for estimating imputation credits. The resulting net tax expenses, which are included in the calculation of our annual revenue requirement, are shown in the Our Revenue Requirement chapter of the Regulatory Proposal and the accompanying Appendix A – Our revenue requirement components.
26.2	Provide details of each departure from the AER's post-tax revenue model for the calculations referred to in paragraph 26.1 and the reasons for that departure.	There are no departures from the AER's PTRM. We have used the latest available version of the AER's PTRM (Version 3, January 2015) to calculate the TAB for each year of the 2019–24 regulatory period. The tax inputs for the PTRM come from the output of the RFM and therefore incorporate the AER's methodology for calculating weighted average remaining tax lives. Tax depreciation is calculated using the straight-line methodology contained in the PTRM. The PTRM calculates the TAB in each year of the regulatory period by starting with the opening value of the TAB for 2019-20 from the RFM, adding net capital expenditure and deducting tax depreciation.
26.3	Identify each change to standard tax asset lives for existing asset classes from the previous determination. Explain the reason(s) for the change and provide relevant supporting information, including Federal tax laws governing depreciation for tax purposes.	There are no changes to standard tax lives for existing asset classes from those in the previous determination.
26.4	Describe the method used to depreciate existing asset classes as at 1 July 2019 (the start of the forthcoming regulatory control period) for tax purposes and provide supporting calculations, if the approach differs from that in the roll forward model.	We are using the method is outlined in the AER's RFM (Attachment 9.2 to our regulatory proposal). There is no deviation from this approach, so no supporting calculations are provided,
26.5	Provide Essential Energy's calculation of the tax asset base for the relevant system in respect of standard control services for each regulatory year of the current regulatory control period using the AER's roll forward model, which is to be submitted as part of the regulatory proposal.	See RFM (Attachment 9.2 to our regulatory proposal). The TAB is rolled forward using the same methodology as the RAB with the following exceptions: › The opening tax values and tax asset lives (standard and remaining) are inputted into the RFM. › Actual tax depreciation is used rather than forecast depreciation. › Customer contributions are not deducted from the TAB. › The TAB is not indexed for inflation. The opening tax values and tax assets lives used in the RFM are taken from the AER's 2015 Final Determination PTRM. Actual tax depreciation is calculated using the straight-line methodology, as contained in the RFM.

RIN section	Requirement	Essential Energy Response
26.6	Provide details of each departure from the underlying methods in the AER's roll forward model for the calculation referred to in paragraph 26.5 and the reasons for that departure.	There are no departures from the underlying methods in the AER's RFM.
26.7	Identify each difference in the capitalisation of expenditure for regulatory accounting purposes and tax accounting purposes. Provide reasons and supporting calculations to reconcile any differences between the two forms of accounts.	There are no differences in the capitalisation of expenditure for regulatory and tax accounting purposes within the PTRM (refer to Attachment 9.1 of our regulatory proposal).

Miscellaneous reporting

27. Related party transactions

RIN section	Requirement	Essential Energy Response
27.1	Identify and describe all entities which:	Note only
27.1 (a)	are a related party to Essential Energy and contribute to the provision of distribution services; or	We do not have any related parties.
27.1 (b)	have the capacity to determine the outcome of decisions about Essential Energy's financial and operating policies.	The NSW Treasurer and the NSW Minister for Energy and Utilities are the two Shareholding Ministers for Essential Energy on behalf of the State of NSW. The State Owned Corporations Act 1989 gives Shareholding Ministers the authority and responsibility to influence our Statement of Corporate Intent (SCI), which sets out the strategic direction, performance targets and nature and scope of the organisation. NSW Treasury, through Treasurer Directions, can influence our financial and operating policies. Comprising all Ministers, NSW Cabinet's role is to direct overall Government policy and make decisions about State issues.
27.2	Provide a diagram of the organisational structure depicting the relationships between all the entities identified in the response to paragraph 27.1.	The Treasurer is a Shareholding Minister for Essential Energy and has Treasurer Direction power under a number of laws. We are not aware of any Directions relating to specifically to distribution services.
27.3	Identify:	Not applicable to Essential Energy
27.3 (a)	all arrangements or contracts between Essential Energy and any of the other entities identified in the response to paragraph 27.1 currently in place or expected to be in place during the period 2017-18 to 2023-24 which relate directly or indirectly to the provision of distribution services; and	
27.3 (b)	the service or services the subject of each arrangement or contract.	
27.4	For each service identified in the response to paragraph 27.3(b):	
27.4 (a)	provide:	
27.4 (a) i	a description of the process used to procure the service; and	

RIN section	Requirement	Essential Energy Response
27.4 (a) ii	supporting documentation including, but not limited to, requests for tender, tender submissions, internal committee papers evaluating the tenders, contracts between Essential Energy and the relevant provider;	
27.4 (b)	explain:	
27.4 (b) i	why that service is the subject of an arrangement or contract (i.e. why it is outsourced) instead of being undertaken by Essential Energy itself;	
27.4 (b) ii	whether the services procured were provided under a standalone contract or provided as part of a broader operational agreement (or similar);	
27.4 (b) iii	whether the services were procured on a genuinely competitive basis and if not, why; and	
27.4 (b) iv	whether the service (or any component thereof) was further outsourced to another provider.	

28. Vegetation management compliance

RIN section	Requirement	Essential Energy Response
28.1	Provide compliance audits of vegetation management work conducted by Essential Energy during the current regulatory control period.	See Attachment R12 to this RIN response (Essential Energy Vegetation Compliance Audits v2).

29. Corporate structure

RIN section	Requirement	Essential Energy Response
29.1	Provide charts that set out:	Note only
29.1 (a)	the group corporate structure of which Essential Energy is a part; and	Essential Energy is a State-Owned Corporation, owned wholly by the NSW Government, and does not have any subsidiaries.
29.1 (b)	the organisational structure of Essential Energy.	Refer to the structure provided in Attachment R13 to this RIN response – Essential Energy Organisation Structure.

30. Forecast map of distribution system

RIN section	Requirement	Essential Energy Response
30.1	Provide a forecast map of Essential Energy's distribution system for the forthcoming regulatory control period. This map, together with any appropriate accompanying notes, should also indicate the location of new major network assets proposed to be constructed over the forthcoming regulatory control period.	Refer to the map provided in Attachment R14 to this RIN response - Map of Future Distribution System.

31. Transitional issues

RIN section	Requirement	Essential Energy Response
31.1	Provide information on transitional issues (expressly identified in the NER or otherwise) which Essential Energy expects will have a material impact on it and should be considered by the AER in making its distribution determination. For each issue, set out the following information:	Essential Energy has not identified any transitional issues that should be considered by the AER in making its distribution determination.
31.1 (a)	the transitional issue;	
31.1 (b)	what has caused the transitional issue;	
31.1 (c)	how the transitional issue impacts on Essential Energy; and	
31.1 (d)	how Essential Energy considers the transitional issue could be addressed.	

Assurance requirements

32. Audit and review reports

RIN section	Requirement	Essential Energy Response
32.1	Provide the audit report and review reports as applicable, prepared in accordance with the requirements set out in Appendix C.	Refer to Attachment R15 to this RIN response – RIN Audit Reports.
32.2	Provide all reports from the Auditor to Essential Energy's management regarding the audit review and/or auditors' opinions or assessment.	

Other information

33. Confidential information

RIN section	Requirement	Essential Energy Response
33.1	This clause applies to any information Essential Energy provides:	Refer to Attachment R16 to this RIN response - Table of Confidentiality Claims.
33.1 (a)	in response to Schedule 1;	
33.1 (b)	in a *regulatory proposal* for the *forthcoming regulatory control period* (a Proposal)	
33.1 (c)	in a revision or amendment to a Proposal; and	
33.1 (d)	in a submission Essential Energy makes regarding a Proposal or a revised or amended Proposal; (together, Essential Energy's Information).	
33.2	If Essential Energy wishes to make a claim for confidentiality over any of Essential Energy's Information, provide the details of that claim in accordance with the requirements of the AER's Distribution Confidentiality Guideline, as if it extended and applied to that claim for confidentiality.	
33.3	33.3 Provide any details of a claim for confidentiality in response to paragraph 33.2 at the same time as making the claim for confidentiality.	

34. Compliance with Section 71YA of the NEL

RIN section	Requirement	Essential Energy Response
34.1	Provide a statement attesting that:	Note only
34.1 (a)	Where any expenditure or cost is has been incurred or is forecast to be incurred by *Essential Energy,* as a result of or incidental to a review under Division 3A – *Merits review and other non-judicial review* – of the NEL:	Although Essential Energy has previously had expenditure relating to a review under Division 3A - Merits Review and other non-judicial reviews of the NEL, we have: > Not incurred (or forecast to incur) related costs during 2017/18 (our base year). > (a)i - not included any related expenditure or cost in our capital or operating expenditure for a network revenue or pricing determination. > (a)ii - not recovered any of that expenditure or cost, or any part of that expenditure or cost, from end users. > (a)iii - not sought to pass through any of that expenditure or cost, or any part of that expenditure or cost, to end users. 34.1(b) and 34.1 (b) i is not applicable.
34.1 (a) i	Essential Energy has not included any of that expenditure or cost, or any part of that expenditure or cost, in its capital or operating expenditure for a network revenue or pricing determination; and	
34.1 (a) ii	Essential Energy has not recovered any of that expenditure or cost, or any part of that expenditure or cost, from end users; and	
34.1 (a) iii	Essential Energy has not sought to pass through any of that expenditure or cost, or any part of that expenditure or cost, to end users; or	
34.1 (b)	Where no expenditure or cost has been incurred or is forecast to be incurred by Essential Energy, as a result of or incidental to a review under Division 3A – Merits review and other non-judicial review – of the NEL:	
34.1 (b) i	No such expenditure or cost has been incurred or is forecast to be incurred.	

35. Identification of certain costs in actual capital and operating expenditure

RIN section	Requirement	Essential Energy Response
35.1	For any actual capex or opex reported in response to this notice, identify any part of that expenditure which can be attributed to any expenditure or cost that Essential Energy has incurred as a result of, of incidentals to, a review under Division 3A - Merits review and other non-judicial review - of the NEL	Legal fees incurred relating to Merits Review were classified and reported as unregulated in the 2016-17 RINs

Schedule 2

1. Prepare information

RIN section	Requirement	Essential Energy Response
1.1	Prepare the Microsoft Excel Workbooks attached at Appendix A in the manner and form specified in the worksheets therein and in accordance with this notice.	Attachments R1(a-d) to this RIN response provide the completed Microsoft excel workbooks.
1.2	For information other than forecast information, prepare a basis of preparation in accordance with the requirements specified in Schedule 1. The basis of preparation must:	Attachment R2 to this RIN response provides the Basis of Preparation for historical information addressing the requirements of how information was prepared in Attachments R1(a-d).
1.2 (a)	demonstrate how the information provided is consistent with the requirements of this *notice;*	
1.2 (b)	explain the source from which Essential Energy obtained the information provided;	
1.2 (c)	explain the methodology Essential Energy applied to provide the required information, including any assumptions Essential Energy made;	
1.2 (d)	explain, in circumstances where Essential Energy cannot provide input for a Variable using actual information and therefore must provide input using estimated information:	
1.2 (d) i	why an estimate was required, including why it was not possible for Essential Energy to use Actual Information;	
1.2 (d) ii	the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is Essential Energy's best estimate.	

RIN section	Requirement	Essential Energy Response
1.3	Prepare all information required under this *notice* in a manner and form that is:	Attachments R1(a-d) to this RIN response provides the Microsoft excel workbooks.
1.3 (a)	in accordance with the requirements at Schedule 1 which:	
1.3 (a) i	is in an electronic format;	
1.3 (b) ii	includes any underlying calculations and formulae;	
1.3 (c) iii	is not password protected;	
1.3 (d) iv	where relevant, allows for precedents and dependants to be traced; and	
1.3 (e) v	is fully searchable, in text readable format and is capable of text selection and a 'copy and paste' function being applied to it (we prefer that all files be provided in Microsoft Word, Microsoft Excel or PDF);	
1.3 (f) vi	that is readily available for inspection by, or submission to, the AER.	
1.4	Prepare, using a person(s) who satisfies the requirements of paragraph 2 of the Appendix C, an *audit report* and *review report*(s) (as applicable) in accordance with the requirements of this *notice.*	Refer to Attachment R15 to this RIN response – RIN Audit Reports.

Statutory Declaration

Essential Energy has verified the information specified in the AER's Regulatory Information Notice using the CEO Statutory Declaration specified in Appendix B of the Notice. The signed CEO Statutory Declaration can be found at Attachment R17.

Appendix A – Attachments

Reference	Attachment title
R1	Regulatory Templates (a-d)
R2	Basis of Preparation
R3	Regulatory Proposal Documentation List
R4	Reconciliation of regulatory templates to post tax revenue model
R5	Capital Unit Rates - Methods, Source Data & Results document)
R6	Procurement Procedure
R7	Essential Energy RIN REPEX Categories
R8	Our Demand Side Engagement Strategy
R9	Company Policy – Demand Management
R10	Essential Energy's proposed Enterprise Agreement (EA) and the proposed Far West Enterprise Agreement
R11	Opex Rate of Change model
R12	Essential Energy Vegetation Compliance Audits v2
R13	Essential Energy Organisational Structure
R14	Map of Future Distribution System
R15	RIN Audit Reports
R16	Table of Confidentiality Claims
R17	CEO Statutory Declaration