Attachment 11.1

Response to Schedule 1 of AER's RIN

PWC11.1 - Response to Schedule 1 of AER's RIN - 16 Mar 18 - Public

16 March 2018

Purpose and contents

The purpose of this document is to identify where Power and Water Corporation (referred to as "PWC" in the AER's RIN and as Power and Water within this document) has addressed each requirement of Schedule 1 of the Australian Energy Regulator's (AER) Regulatory Information Notice (RIN) issued on 9 November 2017.

The attached table identifies the AER's requirement and our response. The majority of our responses have already been addressed in the documents we have submitted to the AER in, and accompanying, our regulatory proposal. In these cases, we have referred the AER to the attachment name and reference in our document register, including the relevant section of the document or worksheet of the model. In some cases, we have directly responded to the AER's question in the table without further references. We also have greyed out rows in the table where the AER's request does not directly seek a response, but rather provides qualifying information in respect of a question that follows.

In addition to the attached table, Appendix 1 of this document provides a description of each material assumption as required by question 1.5 of Schedule 1 of the RIN. Appendix 2 provides the forecast map of the distribution system as required by question 29 of Schedule 1 of the RIN.

Table of response to Schedule 1 of AER's RIN

RIN Reference	Requirement	Response/ Cross reference to material provided by Power and Water
1	**PROVIDE INFORMATION**	
1.1	Provide the information required in each *regulatory template* in the Microsoft Excel Workbooks attached at Appendix A, completed in accordance with:	We have provided the information requested in Appendix A of the RIN as found in the following documents: • "Category Analysis RIN Workbooks - Consolidated" (Attachment 11.5) • "Economic Benchmarking RIN Workbooks - Consolidated" (Attachment 11.8) and • "Regulatory Determination Workbooks - Consolidated" (Attachment 11.11).
1.1(a)	this *notice*;	Please see response to 1.1 above confirming that we have provided the information in Appendix A of the RIN. We have provided the information in accordance with the AER's RIN Notice.
1.1(b)	the instructions in the Microsoft Excel Workbooks attached at Appendix A;	Please see response to 1.1 above confirming that we have provided the information in Appendix A of the RIN. The information we have provided complies with the instructions in Appendix A.
1.1(c)	the instructions in Appendix E;	Please see response to 1.1 above confirming that we have provided the information in Appendix A of the RIN. The information we have provided complies with the instructions in Appendix E.
1.1(d)	the service classifications set out in the *framework and approach paper*; and	Please see response to 1.1 above confirming that we have provided the information in Appendix A of the RIN. The information we have provided is consistent with the AER's service classifications set out in the framework and response paper.
1.1(e)	*PWC's cost allocation method.*	Please see response to 1.1 above confirming where we have provided the information in Appendix A of the RIN. The information we have provided is consistent with the cost allocation method previously submitted to the AER.
1.2	Provide any proposed changes to *PWC's cost allocation method* used to allocate costs in accordance with rule 6.15 of the *NER* between *distribution services*.	We confirm that we are not proposing any changes to Power and Water's cost allocation method previously submitted to the AER. As noted above our response to Appendix A of the RIN is consistent with this Cost Allocation Method.

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 *PWC* has complied with this *notice* in respect of:	We have provided a basis of preparation for all data other than forecast information in accordance with this notice and the instructions in Appendix E, as found in the following documents: "Basis of Preparation - Category Analysis Template for 2008-09 to 2016-17" (Attachment 11.2) and "Basis of Preparation - Economic Benchmarking Template for 2005-06 to 2016-17"(Attachment 11.3).
1.3(a)	the information in each *regulatory template* in the Microsoft Excel Workbooks attached at Appendix A; and	Please see response to 1.3 above confirming that we have provided the basis of preparation for the category analysis and economic benchmarking templates. We confirm that the basis of preparation provides information in relation to these templates.
1.3(b)	the information prepared in accordance with the following requirements in Schedule 1 of this *notice:*	Please see response to 1.3 above confirming that we have provided the basis of preparation for the category analysis and economic benchmarking templates. We confirm that the basis of preparation provides information in accordance with Schedule 1 of the AER's RIN notice.
1.3(b)(i)	paragraph 5.1(a)(ii);	Please see response to 1.3 above confirming that we have provided the basis of preparation for the category analysis and economic benchmarking templates. We confirm that the basis of preparation provides information in accordance with Schedule 1 of the AER's RIN notice including paragraph 5.1(a)(ii).
1.3(b)(ii)	paragraph 8.5;	Please see response to 1.3 above confirming that we have provided the basis of preparation for the category analysis and economic benchmarking templates. We confirm that the basis of preparation provides information in accordance with Schedule 1 of the AER's RIN notice including paragraph 8.5.
1.3(b)(iii)	paragraph 13 (13.5 and 13.6);	Please see response to 1.3 above confirming that we have provided the basis of preparation for the category analysis and economic benchmarking templates. We confirm that the basis of preparation provides information in accordance with Schedule 1 of the AER's RIN notice including paragraphs 13.5 and 13.6.
1.3(b)(iv)	paragraph 15 (15.2 and 15.3).	Please see response to 1.3 above confirming that we have provided the basis of preparation for the category analysis and economic benchmarking templates. We confirm that the basis of preparation provides information in accordance with Schedule 1 of the AER's RIN notice including paragraphs 15.2 and 15.3.
1.4	Provide for the purposes of the preparation of the *regulatory proposal*:	

1.4(a)	all consultants' reports commissioned and relied upon in whole or in part;	We are relying on the consultant reports identified in Power and Water's document register, which has been attached to our proposal. Where the author of document is a consultant, this is made clear in the file name as required by the AER.
1.4(b)	all *material* assumptions relied upon;	Appendix 1 of this document identifies each material assumption relied upon in the regulatory proposal.
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 table has been designed to provide the AER with the information in the form required.
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	Please find this information in Power and Water's document register, which has been updated as part of the material provided to the AER on 16 March 2018. We note that the documents have been grouped into relevant categories relating to our regulatory proposal.
1.4(e)	each document identified in paragraph 1.4(d) must be given a meaningful filename in the form: PWC – [Author] – [title] – [date] – [public/confidential], where:	Each document in the Power and Water's document register has been given a meaningful filename in accordance with the AER's instructions.
1.4(e)(i)	**Author** is the author of the file if not *PWC*, for example a consultant or other third party;	Each document in the Power and Water's document register has been given a filename in accordance with the AER's instructions. Please note that if the author is Power and Water we have not repeated this twice in the title. However when the author is a consultant, we have indicated that in the title.
1.4(e)(ii)	**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;	Each document in Power and Water's document register has been given a title in accordance with the AER's instructions.
1.4(e)(iii)	**Date** is a relevant date associated with the file, generally the date the document was created;	Each document in Power and Water's document register has been given a creation date in accordance with the AER's instructions.

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 32 of this *notice* (confidential).	Each document in Power and Water's document register has been given a filename in accordance with the AER's instructions, which makes clear whether the file is public or confidential.
1.5	Provide for each *material* assumption identified in the response to paragraph 1.4(b):	
1.5(a)	its source or basis;	Appendix 1 of this document includes a column in a table outlining the source or basis for each material assumption.
1.5(b)	if applicable, its quantum;	Appendix 1 of this document includes a column in a table outlining the quantum (if applicable) for each material assumption.
1.5(c)	whether and how the assumption has been applied and was taken into account; and	Appendix 1 of this document includes a column in a table outlining whether the assumption has been applied and was taken into account. Specifically, we have noted whether the assumption has been applied to capex and/or opex.
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	Appendix 1 of this document identifies a column in a table outlining the effect of the impact of the assumption. We consider that actual expenditure incurred during the *current regulatory control* period is not a relevant consideration for any assumption, other than that we have assumed in developing our capex forecasts for 2019-20 to 2023-24 that we will deliver our forecast capex program for 2017-18 and 2018-19.
1.5(d)(ii)	the sensitivity of the forecast expenditure to the assumption.	Appendix 1 of this document includes a column in a table outlining the source or basis for each material assumption.

1.6	Provide reconciliation of the capital and operating expenditure forecasts provided in the *regulatory templates* to the ex-ante capital and operating allowances in the *post-tax revenue model* for the *forthcoming regulatory control period*.	We have reconciled the regulatory template information to the PTRM in the model "Reset RIN Population Model" (Attachment 11.16).
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*, for each variation or departure explain:	
1.7(a)	the reasons for the variation or departure, including why it is appropriate;	This information is provided in Section 15 of Power and Water's Regulatory Proposal document ("Incentive schemes"). In summary, we have not proposed any variation to the AER's application in the Framework and Approach paper, but provide additional detail on the specific application of the scheme.
1.7(b)	how the variation or departure aligns with the objectives of the relevant scheme; and	Please see our response to 1.7(a) above where we confirm that we are not proposing any variation to the AER's application of incentive schemes in the Framework and Approach paper.
1.7(c)	how the proposed variation or departure will impact the operation of the relevant scheme.	Please see our response to 1.7(a) above where we confirm that we are not proposing any variation to the AER's application of incentive schemes in the Framework and Approach paper.
2	**CLASSIFICATION OF SERVICES**	
2.1	Identify each classification which departs from a service classification set out in the *framework and approach paper* in the *regulatory proposal* and explain:	We have not modified any service classifications from that set out in the AER's Framework and Approach (F&A) paper. Further information can be found in Section 8 of Power and Water's Regulatory Proposal document (Response to F&A paper).

2.1(a)	the reasons for the departure, including why the proposed service classification is more appropriate; and	Please see response to 2.1 above. We are not proposing a departure to the AER's Framework and Approach paper.
2.1(b)	how the treatment of the service will differ under the proposed service classification in comparison to that in the *framework and approach paper*.	Please see response to 2.1 above. We are not proposing a departure to 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*:	
2.2(a)	provide, in a second set of *regulatory templates*, all information required in each *regulatory template* in accordance with the instructions contained therein, modified as necessary, to incorporate the proposed service classifications; and	As discussed above, we have not modified the service classifications in the AER's F&A and therefore have not provided a second set of regulatory templates.
2.2(b)	identify and explain where the *regulatory templates* differ.	As discussed above, we have not modified the service classifications in the AER's F&A and therefore have not provided a second set of regulatory templates.
3	**CONTROL MECHANISMS**	
3.1	For the proposed forecast revenues that *PWC* estimates to recover from providing *direct control services* over the *forthcoming regulatory control period* provide:	
3.1(a)	formulaic expressions for the basis of control mechanisms for *standard control services* and for *alternative control services*; and	We have set out the formulae and expressions for Standard Control Services (SCS) and Alternative Control Services (ACS) in section 2 and section 5 respectively of the document "Control Mechanisms" (Attachment 1.8)

3.1(b)	a detailed explanation and justification for each component that makes up the formulaic expression.	We have explained and justified each component of the formulae for SCS and ACS as discussed in section 2 and section 5 respectively of the document "Control Mechanisms" (Attachment 1.8)
3.2	Also demonstrate:	
3.2(a)	how *PWC* considers the control mechanisms are compliant with the *framework and approach paper*; and	As noted in the document "Control Mechanisms" (Attachment 1.8), we have used the same formulae as set out in the AER's Framework and Approach paper. As noted below, the only variation relates to the inclusion of an adjustment factor, which in our view is still compliant with the AER's formula in the F&A paper.
3.2(b)	for *standard control services*, how *PWC* considers the control mechanisms are also compliant with clause 6.2.6 and part C of Chapter 6 of the *NER*.	We have adopted the AER's control mechanism for standard control services in the RIN, which we recognise complies with 6.2.6 and part C of Chapter 6 of the NER. The only departure from the AER's control mechanism relates to the inclusion of adjustment factor to give effect to 6.4.3(b)(5A) of the NT National Electricity Rules. This is discussed in section 2 of the document "Control Mechanisms" (Attachment 1.8).
4	**CAPITAL EXPENDITURE**	
4	**General**	
4.1	Provide justification for *PWC*'s total *forecast capex,* including the following information:	
4.1(a)	why the total *forecast capex* is required for *PWC* to achieve each of the objectives in clause 6.5.7(a) of the *NER*;	We have demonstrated how our total forecast capex achieves each of the objectives in 6.5.7(a) of the NT NER in the document "Addressing the Capex and Opex Objectives, Criteria and Factors in the NT NER" (Attachment 1.18).
4.1(b)	how *PWC's* total *forecast capex* reasonably reflects each of the criteria in clause 6.5.7(c) of the *NER*;	We have demonstrated how our total forecast capex reasonably reflects each of the criteria in 6.5.7(c) of the NT NER in the document "Addressing the Capex and Opex Objectives, Criteria and Factors in the NT NER" (Attachment 1.18).
4.1(c)	how *PWC's* total *forecast capex* accounts for the factors in clause 6.5.7(e) of the *NER*;	We have demonstrated how our total forecast capex accounts for the factors in 6.5.7(e) of the NT NER in the document "Addressing the Capex and Opex Objectives, Criteria and Factors in the NT NER" (Attachment 1.18).

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 incorporated; and	We have addressed the regulatory and legislative basis of our proposal in Section 4 of Power and Water's Regulatory Proposal document ("Regulatory baseline"). Section 2.6 and Section 4 of the "Capex overview" document (Attachment 4.1) provides more detail on how our plans, policies and procedures have been incorporated into capex. We also set out the relevant supporting documents relating to each AER capex category in sections 6 to 11 of that document.
4.1(e)	an explanation of how each response provided to paragraph 4.1 (a)-(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.	We have explained the change in capital expenditure between the current and forthcoming period in Section 3 of the "Capex overview document" (Attachment 4.1) and provided further detail on this relationship for each AER capex category in sections 6 to 11 of this document.
4.2	Provide the model(s) and methodology *PWC* used to develop its total *forecast capex*, including:	We have provided the model "SCS and ACS Metering Forecast Capex Model" (Attachment 12.7). We have also outlined our capex forecast methodology in Section 5 of the "Capex Overview" document (Attachment 4.1) and in the "Expenditure Forecasting Method" that we submitted to the AER in 2017.
4.2(a)	A description of how *PWC* prepared the *forecast capex*, including:	
4.2(a)(i)	how its preparation differed or related to budgetary, planning and governance processes used in the normal running of *PWC*'s business;	We largely used our existing budgetary, planning and governance process to develop our capex proposal. When developing the proposal we undertook further scrutiny of our forecasts, by examining existing planning models and processes, and by undertaking a detailed examination of our proposed program. This was to identify whether the proposed program was in the long- term interests of customers as explained further in our response to 4.2(a)(iii) below. This involved early consultation with our customers on our draft plan for the forthcoming period.

4.2(a)(ii)	the processes for ensuring amounts are free of error and other quality assurance steps; and	Our quality assurance process for models and data involved staged peer review, together with management review. In the first instance, we had a modelling team that analysed the data and developed models. The models were peer reviewed by Power and Water staff who were independent of the modelling team to check that the processes were robust, and the resulting amounts were free of error. Inputs to the models, where appropriate, were sourced from the historical data in the Workbooks in Appendix A of the AER's RIN. We are currently having this data audited and intend providing it to the AER in March 2018 once the audit is complete. Much of the data reflects the resulting amounts from the modelling processes we have undertaken, and will provide further assurance of the data. Outputs from the models where reviewed for consistency against the underlying assumptions and other cross checks (e.g. simple trends from history).
4.2(a)(iii)	if and how *PWC* considered the resulting amounts, when translated into price impacts, were in the long term interest of consumers.	Power and Water examined whether the proposed capital program is in the long term interests of customers by considering relevant factors such as price impact, together with factors such as safety and service quality such as reliability and customer service. During our Deliberative Forums, we engaged with customers on the appropriate balance between factors such as price, safety and service quality. During these sessions, customers were presented with our proposal, which was to maintain current reliability and responsiveness levels for the majority of customers (at a system level), and focus on improving reliability for poor performing rural and urban areas (e.g. Lovegrove in Alice Springs, Virginia and Stuart Park in Darwin) at a cost equivalent to approx. $1.70 extra per customer, per year. This proposal was developed after preliminary feedback from our Focus Groups indicated that customers were generally comfortable with current reliability levels, however a small number of customers identified that current reliability was below standard. When we investigated the location of these customers, we identified that they were in our poor performing feeder areas and were experiencing below average reliability. When the proposal was tested, 65% of attendees scored the draft plan on the acceptable side (7 or more out of 10). 46% of customers found the draft plan to be completely acceptable (10 out of 10). This provided us with a level of comfort that our proposed capital program was meeting the long-term interests of customers.

4.2(b)	any source material used (including models, documentation or any other items containing quantitative data): and	We have identified models (which include quantitative data and source material) in our document register attached to our proposal. This material is annotated in those models and explained in our regulatory proposal and supporting attachments. Please see Attachments 12.1 to 12.24 for each model we have relied on as part of our regulatory proposal.
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*.	The calculations to transform source material can be found at "Reset RIN Population Model" (Attachment 11.16).
4.3	Identify which items of *PWC*'s *forecast capex* have been:	
4.3(a)	derived directly from competitive tender processes;	Our cost estimates for projects in our forecast capex are not derived directly from competitive tender processes. However, our cost estimation methodologies rely on historical experience with delivering projects and programs of a similar scope. To the degree that these projects have been contracted to external parties, the costs will be reflected in our cost estimates. This is discussed in our response to 4.3(b) and 4.3(c) below. Further information on our cost estimation methodology can be found in section 4 of the "Capex Overview" (Attachment 4.1).
4.3(b)	based upon competitive tender processes for similar *projects*;	When developing our cost estimates for proposed capital projects we have considered the historical cost of completing projects of a similar nature, including where an external party has delivered the project under a competitive tender process. In particular, our unit cost estimates for building new zone substations has relied (to a degree) on actual costs of external parties that have tendered for the project under either competitive tender, or through a panel arrangement.
4.3(c)	based upon estimates obtained from *contractors* or manufacturers;	For major projects we have used a bottom up approach to estimate costs, which includes consideration of contractor and manufacturer estimates in the past. We note that we have panel arrangements in place under our procurement processes, and continually test the market.
4.3(d)	based upon independent benchmarks;	We commissioned Nuttall Consulting to apply the AER's Repex model to benchmark our repex forecasts with our internal costing methods. Further information can be found in "Nuttall Consulting– Repex report" (Attachment 5.1).

4.3(e)	based upon actual historical costs for similar *projects*; and	We have used averages of historical costs to determine the forecast unit rate for smaller projects and for "pooled" programs such as replacing assets that have failed in service. We have tested the resultant cost estimate against available independent benchmarks such as the AER's repex model.
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.	Our unit cost estimates do not include a specific item for risk or uncertainty. We have no unspecified contingency factors.
4.4	Provide all *documents* which were materially relied upon and relate to the *deliverability* of *forecast capex* and explain the proposed *deliverability*.	We have not relied on any specific documents to show that the forecast capex can be delivered. However we note that Power and Water is well placed to deliver the proposed capital program. This is demonstrated by our ability to deliver a capital program that was higher than the allowance provided under our previous regulator. We will also be implementing outsourcing strategies in a maturing external market that will assist us to efficiently deliver the capital program in the forthcoming period.
4	**Capex categories**	
4.5	Describe each *capex category* and expenditures comprising these categories identified in the *regulatory templates*, including:	Section 10 of our Regulatory Proposal document provides a general description and definition of each capex category in the regulatory templates. Further information can be found in the "Capex Overview Document" (Attachment 4.1).
4.5(a)	key drivers for expenditure;	Section 10 of our Regulatory Proposal document describes the key drivers of expenditure for each AER capex categories. Further detailed for each AER capex category can be found in sections 6 to 11 of the "Capex Overview Document" (Attachment 4.1).
4.5(b)	an explanation of how expenditure is distinguished between:	
4.5(b)(i)	greenfield driven and reinforcement driven *augmentation capex*;	Our augmentation programs are based on the least cost solution to address a constraint. The solution may either be the construction of new assets, which we interpret as "greenfield", or upgrading the capacity of existing assets, which we interpret as "reinforcement". Further information can be found in section 7 of the "Capex Overview Document" (Attachment 4.1).

4.5(b)(ii)	connections expenditure and *augmentation capex*;	Connections capex is required to service new, altered or upgraded connections for residential, commercial and industrial customers. In contrast, the key driver of augex is growth in maximum demand, caused by population growth or specific development within localised parts of our distribution network where there are forecast to be capacity constraints. The distinction is addressed in Section 10 of our regulatory proposal document. Further information can be found in sections 7 and 8 of the "Capex Overview Document" (Attachment 4.1).
4.5(b)(iii)	replacement capex driven by condition and *asset* replacements driven by other drivers (e.g. the need for greenfield and reinforcement driven *augmentation capex*); and	Sections 6,7 and 8 of the "Capex Overview Document" (Attachment 4.1) explain that replacement capex is driven by condition and safety risk of asset failures, as distinguished from augmentation drivers such as growth in maximum demand, or new, altered or upgraded connections.
4.5(b)(iv)	any other *capex category* or *opex category* where *PWC* considers that there is reasonable scope for ambiguity in categorisation.	We have not identified any other ambiguities.
5	**REPLACEMENT CAPITAL EXPENDITURE MODELLING**	
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:	
5.1(a)	For individual *asset* categories set out in the *regulatory templates*, provide in a separate *document*:	
5.1(a)(i)	a description of the *asset* category, including:	The description of individual asset categories relating to template 2.2 can be found in "Basis of Preparation - Category Analysis Template for 2008-09 to 2016-17" (Attachment 11.2). We have used the same definitions for forecast information in completing 2.2 of "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11).

5.1(a)(i)(A)	the *assets* included and any boundary issues (i.e. with other *asset* categories);	All boundary issues have been discussed in our description of template 2.2 in "Basis of Preparation - Category Analysis Template for 2008-09 to 2016-17" (Attachment 11.2). We have used the same definitions for forecast information in completing template 2.2 of "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11).
5.1(a)(i)(B)	an explanation of how these matters have been accounted for in determining quantities in the age profile;	In general, these boundary issues have not impacted the quantities in the age profiles. An exception relates to the replacement of pole-top clamps with splices, which has been treated as the replacement of 1m of conductor.
5.1(a)(i)(C)	an explanation of the main drivers for replacement (e.g. condition); and	Please see Section 10.4 of the Regulatory Proposal document for a description of the overarching drivers for replacement. We have also set out detailed information on drivers of replacement in Attachments 13.1 to 13.45, Attachments 14.1 to 14.4 and Attachments 15.1 to 15.7 which we submitted to the AER on 28 February 2018.
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.	In general, our cost estimate relates to the complete replacement of the asset, or the complete cost of refurbishing an asset. An exception relates to cable and overhead conductors, which may involve replacing a section of the cable or conductor at the time a fault arises. We have used historical data to estimate the cost and quantity of these segments.
5.1(a)(ii)	an estimate of the proportion of *assets* replaced for each year of the *current regulatory control period*, due to:	
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;	Almost all asset replacements are due to condition and obsolesce. There may be a few examples where we replace the entire zone substation due to issues with major assets within the substation. In these cases there may be assets within the substation that do not have condition issues, on the basis that it is more cost efficient to replace the entire zone substation rather than just the major components.
5.1(a)(ii)(B)	replacements due to other factors (and a description of those factors);	As explained above, some functioning elements of a zone substation may be replaced as part of overall condition issues with the substation.

5.1(a)(ii)(C)	additional *assets* due to the *augmentation*, extension, development of the *network*; and	We have proposed reliability and quality of supply expenditure, which we have separated into a replacement component and an augmentation component. This is discussed in section 6.5.4 and 7.5.3 of the "Capex Overview Document" (Attachment 4.1).
5.1(a)(ii)(D)	additional *assets* due to other factors (and a description of those factors).	In replacing assets, we are likely to use different technology and modern equipment relative to the original design of the asset being replaced. However, the asset would still perform the same function. In some cases, our network standards may require a different standard or design compared to the asset being replaced.
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:	
5.1(b)(i)	rules, codes, licence conditions, statutory requirements;	Section 3.2 of the "Capex Overview document" (Attachment 4.1) provides a summary of the drivers and factors that have impacted total capex (including network replacement expenditure requirements). We have also separated our replacement capital expenditure into the following categories, as described in section 6 of Attachment 4.1: • Condition and risk – replacement projects and programs to address an identified condition, technical obsolescence or risk to safety and continuity of supply. • Compliance driven – replacement projects to meet the requirements of the Network Technical Code and Network Planning Criteria. • Reliability and quality of supply. The compliance driven replacement capital expenditure is described in section 6.5.3.

5.1(b)(ii)	internal planning and *asset* management approaches;	Section 3.2 of the "Capex Overview document" (Attachment 4.1) describes two key changes to our internal planning and asset management approach that have impacted the trend in capex: • In September and October 2008, several electrical equipment failures at Casuarina Zone Substation resulted in widespread, sustained power disruption to Darwin's northern suburbs. Consequently, the NT Government established an independent enquiry. The recommendations led to a significant increase in our replacement capex, particularly on replacing zone substations, a program that continued into the current period. • We have significantly improved our asset management practices in recent years, which impacts our program in the forthcoming period. For example, our new health and criticality methodology supports an efficient decision-making process on risk within an asset class.
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;	Section 6 of the "Capex Overview document" (Attachment 4.1) identifies key drivers of replacement capex in the forthcoming period, with reference to factors such age, risk profiles, and condition. The section sets out the replacement capex by categories that relate to the underlying driver. For example, we have identified programs related to a safety driver.
5.1(b)(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 11.7 and 11.8);	We note that demand growth and customer numbers have not influenced the replacement capex forecast in the forthcoming period. We have not identified any other external factors such as a specific change to legislation.
5.1(b)(v)	technology/solutions to address needs, covering:	
5.1(b)(v)(A	network; and	Section 6 of the "Capex Overview document" (Attachment 4.1) notes that some of our forecast replacement capex is driven by technical obsolescence, including where vendor or manufacturer support has been withdrawn and spares are exhausted. These issues particularly impact protection and control, and secondary systems assets where unavailability of support and/or spares can result in extended outages.

5.1(b)(v)(B)	non-network.	We have not identified a specific non-network solution for replacement projects in the forthcoming period. Further information on our approach to non-network solutions and demand management is found in our response to Question 10 of this table.
5.1(b)(vi)	any other significant matters.	We have not identified any other significant matters.
5.1(b)(vii)	Identify and provide information or documentation to justify and support any responses to paragraph 5.1(b) (i)-(vi).	Our document register includes the following documents relevant to the questions above: • Regulatory proposal document (Section 10) • Capex overview document (Attachment 4.1) • Nuttall Consulting – Repex Report (Attachment 5.1) Further detailed information relating to replacement capex can be found in Attachments 13.1 to 13.45, Attachments 14.1 to 14.4 and Attachments 15.1 to 15.7 which we submitted to the AER on 28 February 2018.
5.1(b)	The information provided in response to paragraph 5.1(b) above should at least distinguish between the *asset* categories identified in response to paragraph 5.1(a).	We have provided information to support expenditure by some AER repex categories at Attachments 14.3 to 14.12, which we submitted to the AER on 28 February 2018.
6	**AUGMENTATION CAPITAL EXPENDITURE MODELLING**	
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).	
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*:	

6.2(a)	Separately for *sub-transmission lines*, *sub-transmission* and *zone substations*, *HV feeders* and *distribution substations*, *PWC* must explain how it:	
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:	For sub-transmission lines the source data and method is the document "Annual Transmission Planning Report 2013-14" (Attachment 4.6). For sub-transmission and zone substations, the method is set out in Appendix 3 and 4 of "AEMO: Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4). For high voltage feeders, we have not provided data at 50% probability of exceedance. Our method is also documented in Attachment 4.4. For distribution substations, we have not provided 50% Probability of Exceedance (POE) forecasts as we have used actual data without weather correction.
6.2(a)(i)(A)	how this value relates to the *maximum demand* that would be used for normal planning purposes;	In general, the 50% POE value is used for normal planning purposes for sub-transmission lines, sub-transmission and zone substations and high voltage feeders. A key exception is where there is only a single transmission line or a single transformer in a substation in which case a 10% POE value is used. As described in our response to 6.2(a)(1) above, we do not forecast a 50% POE forecast for distribution substations, so this is not used for planning purposes.
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;	For sub-transmission lines, sub-transmission substations and zone substations, and high voltage feeders, please refer to description of template 5.2 in "Basis of Preparation - Category Analysis Template for 2008-09 and 2016-17" (Attachment 11.2). Please also refer to "AEMO: Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017"(Attachment 4.4). For distribution substations, we have not provided at 50% POE, as we have historical values without weather correction.
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	For historical data for sub-transmission lines please refer to the "Annual Transmission Planning Report 2013-14" (Attachment 4.6). For sub-transmission, zone substations and high voltage feeders we have set out our method in the section relating to template 5.2 in "Basis of Preparation - Category Analysis Template for 2008-09 to 2016-17." (Attachment 11.2). The 2017-18 method follows our latest procedure developed by AEMO and contained in the document "AEMO - Maximum Demand And Customer Connections Forecasting Procedure" (Attachment 4.5). For distribution substations we have estimated the data.

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.	For sub-transmission lines, sub-transmission substations and zone substations please refer to our description of template 5.2 in "Basis of Preparation - Category Analysis Template for 2008-09 to 2016-17." (Attachment 11.2) which documents the relationship to raw unadjusted maximum demand. We would expect 10% POE to be significantly higher than 50% POE forecasts. For high voltage lines and distribution substations, we would expect the relationship to correspond to raw unadjusted maximum demand once normalised for switching and no weather correction. 10% POE would not be significantly different as there is less diversification at this level.
6.2(a)(ii)	Determined the rating data provided in the *asset* status *tables* 2.4.1 to 2.4.4, including where relevant:	For sub-transmission lines, we use thermal ratings based on design rating, but consider ratings under N-1 contingency. For sub-transmission and zone substations we use thermal rating based on nameplate. For sub-transmission and zone substations refer to description relating to template 5.4 in "Basis of Preparation - Category Analysis Template for 2008-09 to 2016-17" (Attachment 11.2). For high voltage feeders and distributions substations, we use the nameplate ratings, or the manufacturer assigned rating adjusted for installation conditions. We de-rate cables that leave the zone substation and sub-transmission stations to 80 per cent.
6.2(a)(ii)(A)	the basis of the calculation of the ratings in that segment, including *asset* data measured and assumptions made; and	For sub-transmission line, sub-transmission substations, zone substations we have set our method in our description of template 5.4 in "Basis of Preparation - Category Analysis Template for 2008-09 to 2016-17." (Attachment 11.2) For sub-transmission lines we use 'as designed' ratings as the thermal ratings. N-1 Emergency line ratings are based on historical precedence. For high voltage feeders we use the manufacturer's rating of cable type under nominal system conditions (based on our Network Technical Code and Network Planning Criteria) and derate to 80% capacity where cables leave the zone substation/sub-transmission station to allow for mutual heating. Distribution substations assume the nameplate rating as the cyclic rating.
6.2(a)(ii)(B)	the relationship of these ratings with *PWC*'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.	For sub-transmission lines, sub-transmission substations and high voltage lines, these are the same values. These values were not used for distribution substations, and were specifically estimated for the RIN.

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 *PWC*.	For sub-transmission lines, sub-transmission substations and high voltage lines please refer to document "AEMO: Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4). For distribution substations, we have assumed year on year growth as per most recent historical values.
6.2(b)	In relation to the *capex*-capacity *table* 2.4.6, *PWC* must explain:	
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;	The costs of a project include the direct costs of undertaking the augmentation program or project including labour and contract staff hours booked directly to the project, materials, and other activities relating to the project such as project management. We have not identified non-field analysis activities and management costs as a direct cost where these do not relate to a specific activity related to an augex project. These costs are captured as a network or corporate overhead in the RIN.
6.2(b)(ii)	how it determined and allocated actual *capex* and capacity to each of the segment groups, covering:	
6.2(b)(ii)(A	the process used, including assumptions, to estimate and allocate expenditure where this has been required; and	For a full discussion please see our description of template 2.3(a) in "Basis of Preparation - Category Analysis Template for 2008-09 to 2016-17"(Attachment 11.2). In summary, where a project had zone substation assets but no sub-transmission line assets, it was classified as a zone substation project. Conversely, where a project had sub-transmission line assets and no zone substation assets, it was classified as a sub-transmission line project. Where a project had both types of assets, it was classified in accordance with the asset type that contributed the highest capital cost.

6.2(b)(ii)(B)	the relationship of internal financial and/or *project* recording categories to the segment groups and process used.	For a full discussion please see our response to template 2.3(a) in "Basis of Preparation - Category Analysis Template for 2008-09 to 2016-17" (Attachment 11.2). In summary, we use our internal cost codes to identify if a project is an augmentation. Any capital project with a work type code of "EXTENSIONS" and which is not part of the code "CUSTOMER CONNECTIONS", "CUSTOMER AUGMENTATION" or "NLS" programs was assigned to augmentation. In some cases we identified incorrect labelling in our systems, in which case the relevant assets were manually adjusted. It should be noted that the nominated segments do not directly relate to our internal processes. Rather we identify individual projects and programs to meet constraints. For this reason we have had to manually allocate the data outside of our normal business systems to provide the AER with the required information.
6.2(b)(iii)	how it determined and allocated estimated/*forecast capex* and capacity to each of the segment groups, covering:	
6.2(b)(iii)A	the relationship of this process to the current *project* and *program* plans; and	We note that we would not undertake the segmentation required by the AER as part of our normal business planning process. For this reason we have allocated capacity and capex to segment groups based on a manual process that we discuss in relation to template 2.3(a) in "Basis of Preparation - Category Analysis Template for 2008-09 to 2016-17"(Attachment 11.2). The same process has been used for forecast information in "Regulatory Determination Workbooks – Consolidated".
6.2(b)(iii)B	any other higher-level analysis and assumptions applied.	We have not identified any other material higher-level analysis or assumptions that are material.
6.2(c)	Describe the *projects* and *programs PWC* has allocated to the unmodelled *augmentation* categories in *table* 2.4.6, covering:	Augmentation was considered unmodelled if the project driver was not directly related to addressing peak demand or capacity needs. Some examples of unmodelled augmentation include: - Installation of a new dehumidifier in an existing zone substation. - Installation of a new recloser to address reliability issues. - Installation of a new pole to raise high voltage line clearances.
6.2(c)(i)	the proportion of unmodelled *augmentation capex* due to this *project* or *program* type;	The proportion of unmodelled augmentation is approximately 20 per cent.

6.2(c)(ii)	the *primary drivers* of this *capex*, and whether in *PWC*'s view, there is any secondary relationship to *maximum demand* and/or utilisation of the *PWC network*; and	Primary drivers include: • Reliability for improving reliability for poor performing rural and urban areas (e.g. Lovegrove in Alice Springs, Virginia and Stuart Park in Darwin) for instance by installing reclosers. • Public Safety – for example installing new poles to raise high voltage clearances. Other drivers include installing new supporting assets such as dehumidifies to ensure the continued functionality and longevity of primary assets such as zone substations.
6.2(d)	Separately for each *network* segment that *PWC* defined in the model segment data *Workbook 1 – regulatory determination, regulatory template* 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 *PWC network* to supply *customer* demand at similar service levels, or the improvement in service levels for a similar *customer* demand level:	We confirm that a key assumption of our capex forecast is to maintain, but not improve, system-wide security of supply and network reliability, consistent with clause 6.5.7 of the NER. On this basis, the programs and projects seek to increase the capability of Power and Water's network to supply customer demand at similar service levels.
6.2(d)(i)	Describe the *network* segment, including:	The networks segments are: • Sub-transmission lines -all • Sub-transmission substations and zone substations • High voltage feeders – all • Distribution substations - all
6.2(d)(i)(A)	the boundary with other connecting *network* segments; and	The capex for each network segment is generally split according to the physical boundary of the assets. • Sub-transmission lines – the first span not including the landing span. • Sub-transmission substations – all assets in the boundary of the substation including the landing span. For zone substations - all assets in the boundary of the substation including the landing span and the circuit breaker. • High voltage feeders – the cable including the termination connecting to the circuit breakers. • Distribution substations – including protection hardware.

6.2(d)(i)(B)	the main reasoning for the individual segment (e.g. as opposed to forming a more aggregate segment).	The segments in our view best suit the augex model, and was capable of bring aligned to Power and Water's asset classes. Further information can be found in section 3.2.1 of "Nuttall Consulting – Augex Report" (Attachment 6.1) which was submitted to the AER on 28 February 2018.
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;	The method, data sources, and assumptions for the utilisation threshold statistics can be found in section 3.2.2 and 3.3.3 of "Nuttall Consulting – Augex Report" (Attachment 6.1) which was submitted to the AER on 28 February 2018.
6.2(d)(ii)(B)	the relationship to internal or external planning criteria that define when an *augmentation* is required;	Power and Water's planning criteria is based upon Network Technical Code and Network Planning Criteria and this is the primary factor in determining the timing of the augmentation. Please see "Network Technical Code and Network Planning Criteria" (Attachment 4.2) for a more detailed understanding of how our criteria is reflected in our decisions on when to augment the network.
6.2(d)(ii)(C)	the relationship to actual historical utilisation at the time that *augmentations* occurred for that *asset* category;	Power and Water has used the augex model calibration to calculate the utilisation threshold for the historical period rather than the actual historical utilisation.
6.2(d)(ii)D	PWC's views on the most appropriate probability distribution to simulate the *augmentation* needs of that *network* segment; and	At this stage Power and Water has not undertaken any analysis on the best probability distribution to apply to the utilisation threshold in the augex model to simulate the needs of the network for each segment. For this reason we are not in a position to provide an expert view.
6.2(d)(ii)(E)	the process applied to verify that the parameters are a reasonable estimate of utilisation limit for the *network* segment.	Power and Water's process involved comparing the actual results to assess the validity of the augex model calibration results.
6.2(d)(iii)	Regarding the *augmentation* unit cost and capacity factor provided, provide an explanation of each of:	
6.2(d)(iii)A	the methodology, data sources and assumptions used to derive the parameters;	The methodology used to derive the parameters is provided in section 3.2.2 and 3.3.3 of "Nuttall Consulting – Augex Report" (Attachment 6.1) which was submitted to the AER on 28 February 2018.

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*;	The historical unit rate and capacity factor were calculated using the actual capex and capacity added. The forecast unit rate and capacity factor were calculated using the forecast capex and capacity added from Power and Water's plans.
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	We think the possibility that we have double counted any capex or capacity added would be very low, as we have separated our reporting into distinct network segments.
6.2(d)(iii)(D)	the process applied to verify that the parameters are a reasonable estimate for the *network* segment.	The parameters for the historical and forecast periods were compared to determine whether they were reasonable. It should be noted that the unit rates and capacity factors were found to be highly dependent on the actual projects that were conducted in the respective periods.
6.2(e)	Explain the factors *PWC* considers may result in different *augmentation* requirements for itself as compared to other NEM-based DNSPs. *PWC* must account for the degree that different *augmentation* requirements are driven by differences in *asset* utilisation and *maximum demand* growth. *PWC* 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:	Our Executive Summary, and chapter 3 of the regulatory proposal draw out unique factors such as our geographic remoteness, peak load profile including a long sustained peak, major customers located in isolated regions, demanding operating conditions due to extreme weather, and the design of our network which effectively represents three stand-alone networks with diseconomies of scale compared to more dense network.
6.2(e)(i)	the maximum achievable utilisation of *assets* for *PWC*; and	We are not able to comment on other DNSPs. We note that the long afternoon peak will impact the utilisation of the network.

6.2(e)(ii)	the likely *augmentation project* and/or cost.	The nature of our network influences the timing and options for when we augment the network. For example: • Due to geographic isolation, our customers face long restoration times when we are unable to meet demand, for instance when there is insufficient redundancy to provide load after a failure of an asset. • The sustained afternoon peak means that demand management solutions need to operate for longer periods, limiting opportunities to utilise lower cost demand management solutions to address network constraints. The difficult operating conditions due to extreme weather, long distances, and access issues would likely result in higher inherent costs of undertaking augmentation activity relative to other DNSPs. Further, due to extreme weather, our network design standards need to consider how our assets can withstand extreme weather events.
6.2(e)	For each significant factor discussed, *PWC* must indicate relevant model segments and estimate the impact these factors will have on its *augmentation* levels and associated *capex* compared to other DNSPs.	Our demand forecasts take into account loss of major customers and penetration of rooftop PV. These demand forecasts have been incorporated in each network segment. It is difficult to quantify how the other factors specifically lead to cost differentials between Power and Water and other DNSPs without a full knowledge of other DNSPs.
7	**CONNECTIONS EXPENDITURE**	
7.1	Provide and describe the methodology and assumptions used to prepare the forecasts of *connection* works including:	
7.1(a)	Estimation of *connection* unit costs for each *customer* type; and	The unit cost per connection type was developed based on the 2016-17 actual aggregate cost per connection type divided by the number of connections per customer type. A base year unit rate (expressed in real FY 19) was established by indexing the 2017 values to FY 2019 consistent with the assumptions that underlie the regulatory proposal.

7.1(b)	Connection volumes for each *customer* type.	The annual volume per connection type was developed by using two data sources. Firstly, AEMO's forecast of connection volumes in the document "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4). Secondly the values for 2017 in Table 2.5.3 of our response to "Category Analysis RIN Workbooks – Consolidated" (Attachment 11.5) The AEMO report is based on 10 years of historical customer number connections provided by Power and Water, and applies regression coefficients based on GSP and population growth. Please note that these are "active" connections that reflect the cumulative number of new connections less disconnections, and will be a smaller number than new connections. The issue is that as a result whilst the AEMO forecasts are used to determine pricing they are not in the same "currency" as the unit cost, which is based on the number of new connections. Please note that Power and Water only has records of the past 4 years of numbers of new connections by customer type. To mitigate this, the AEMO annual total customer number was converted to a series of annual incremental percentage changes over the forecast period commencing 2017-18 through to 2023-24. The incremental 2018 percentage change was then globally applied to the real year 2017 number of new connections for each customer connection type to form the first forecast year 2018. The forecast for the remaining years out to 2024 simply multiplies the incremental percentage change by the previous year number of new connections. The algebraic description of this is as follows: $$NC_t = \left(\frac{AFN_t - AFN_{t-1}}{AFN_{t-1}}\right) \times NC_{t-1}$$ Where : NC_t = Number of new connections per connection type in year t. NC_{t-1} = Number of new connections per connection type in year t-1. (base year being the Power and Water's 2017 CA RIN data point) AFN_t = Total number of active connections sourced from the AEMO report in year t. AFN_{t-1} = Total number of active connections sourced from the AEMO report in year t-1.
7.2	PWC must provide its estimation of *customer contributions* based upon the estimated life and revenue to be recovered from *connection assets*, including:	Connection charges apply to extension works to the existing shared network performed by Power and Water. Our proposed connection policy proposed to recover the full costs from customers. For this reasons there is no cost-revenue test or calculation. Please refer to "Proposed Customer Connection Services Policy" (Attachment 7.2).
7.2(a)	the expected life of the *connection*;	As discussed in 7.2 above, our proposed connection policy does not include a revenue / cost threshold or calculation, so this question does not have application to our circumstances.

7.2(b)	the *average* consumption expected by the *customer* over the life of the *connection*; and	As discussed in 7.2 above, our proposed connection policy does not include a revenue / cost threshold or calculation, so this question does not have application to our circumstances.
7.2(c)	any other factors that influence the expected recovery of the *distribution network* use of system charge to *customers*.	We have not identified any other factors.
8	**NON-NETWORK ALTERNATIVES**	
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.	We applied our demand management policy as part of the business as usual planning processes.

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.	There are a number of unique factors in our network that influenced how demand management solutions could be utilised to reduce capital and operating costs. These include: • NT commitment to renewable generation - Following on from the Langworthy Panel review, the Northern Territory Government committed to a 50% renewable target by 2050. This will likely incentivise more embedded and household generation, together with battery storage. • Load profile - Power and Water has a unique load profile compared to other DNSPs. We have a sustained afternoon peak in the wet season. This means that Photovoltaic (PV) generation is more effective at providing support to the network during peak times. In turn, this provides the potential to reduce peak demand growth, lessening the need to augment and upgrade the network. However, a long duration peak means that non-network solutions need to provide more hours of support, which greatly increases the relative cost and viability of non-network solutions. • Relative immaturity of non-network solutions market – While we have been actively exploring solutions with non-network providers, the market is relatively immature. The AER's demand management incentive schemes, together with the Government's commitment to renewable energy will encourage more participants in the market. In this context, there were a number of ways that we considered demand management opportunities in the short and long term when developing our regulatory proposal. 1. AEMO's modelling of our demand forecasts for 2019-24 incorporated the expected reduction in capex from renewable generation sources. This has resulted in a lower demand forecast, and reduced the need to augment the network. 2. We analysed whether a non-network solution was possible for forecast capital projects, or could reduce our operating costs. We discuss this further in our response to question 8.3(b). 3. Our network solutions have sought to reduce or defer capital costs to reflect changes in our peak demand environment. For example, when replacing assets we have used lower capacity assets in projects such as replacement of Berrimah Zone Substation, where we are replacing the existing 2 x 38MVA transformers with 2 x 27MVA units. We have also implemented staged approaches to augmenting assets in growing areas, such that we can defer investment and not over-invest if demand growth flattens. For example, we are using a Nomad transformer solution in the Archer substation, which only turns on when an injection of peak demand is required, and defers investment for as long as possible. 4. We have changed our policy to incentivise PV installation by customers by reducing the costs to upgrade to a smart meter. This will encourage more PV and lead to broad based Demand Management (DM). 5. The combination of our smart meter rollout, and proposed changes to tariff structures will provide greater incentives for our customers to reduce energy use at peak times. For instance, our TSS proposes a peak energy charge for weekdays between 12 to 9pm, corresponding more closely to peak hours of energy use. Our smart meter rollout will also provide more information to customers on how they can lower their bill by shifting energy use to outside of the peak.

8.3	Identify each non-network alternative that *PWC* has:	
8.3(a)	commenced during the *current regulatory control period*; and	The key project relates to defer a potential $14 million sub-transmission line augmentation in Alice Springs by working with a generation customer to install a battery that provided the necessary support.
8.3(b)	selected to commence during, or will continue into, the *forthcoming regulatory control period*.	We have assessed each material project in our forecast capex to assess if there may be potential non-network solutions in the remainder of the current or forthcoming regulatory period. We were not able to identify viable non-network solutions at this stage of planning. We will re-assess demand management opportunities as we get closer to commencing the project during the forthcoming period, consistent with the processes in our Demand Management Policy. Our high level analysis looked at the nature of the constraint, and potential for non-network solutions to provide a viable and efficient solution to defer the project. Based on our assessment, there did not appear to be any clear examples of where a non-network solution could be viable. For example: • Wishart Zone substation was not suitable for non-network due to the substantial block loads we forecast due to land release and development. Further there were associated voltage issues due to the distance from existing zone substations of the new land being released in the East Arm area. • For Archer substation, instead of installing a third transformer we are proposing a low cost "Nomad" solution using a mobile transformer that would only run when peak demand was high. A non-network solution was not likely to be economically viable in comparison. • Many of our larger replacements are a single point of supply, so there are no opportunities to retire (rather than replace) the asset. However, for some projects we are replacing the existing two transformers with a single transformer with a connection for the Nomad, reducing the capital cost of the project. • Many of our replacement projects are safety driven. For example, the primary driver for upgrading our Darwin sub-transmission lines relates to issues with clearance that gives risk to public safety. • There are limited opportunities for non-network solutions for replacing corroded poles or SCADA equipment.

8.4	For each non-network alternative identified in the response to paragraph 8.3, provide a description, including cost and location.	As discussed in 8.3(a), the location of this project was Alice Springs. We did not pay for the non-network solution (battery) but benefited the customer by working with them on a solution that deferred a $14 million sub-transmission line.
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 *PWC* to an *Embedded Generator* in reflection any costs avoided by deferring *augmentation* of:	No payments were made to an embedded generator in the current period, and no forecast payment in the forthcoming regulatory period.
8.5(a)	PWC's distribution *network*; or	No payments were made to an embedded generator in the current period, and no forecast payment in the forthcoming regulatory period.
8.5(b)	the relevant transmission *network*.	No payments were made to an embedded generator in the current period, and no forecast payment in the forthcoming regulatory period.
9	**FORECAST INPUT PRICE CHANGES**	
9.1	Provide, in *Workbook 1 – regulatory determination, regulatory template CPI,* the CPI series and index used by *PWC* in estimating *PWC's forecast capex* proposal and the forecast *opex* proposal.	We used the June CPI series for the eight capital cities that is published quarterly by the Australian Bureau of Statistics (ABS) for historical inflation up to June 2017. We have provided the CPI series in "Category Analysis RIN Workbooks – Consolidated" (Attachment 11.5) in accordance with the AER's instructions. This CPI series is also replicated in various models that we are submitting, for instance "Proposal tables and charts" (Attachment 12.20), "SCS opex model" (Attachment 12.4), and "ACS metering opex model" (Attachment 12.5). The CPI series in these models convert historical values in to real $2019, together with inflation forecasts published by the Reserve Bank of Australia in its November 2017 Statement on Monetary Policy. We note that this series differs from that used to roll-forward the RAB over the 2014-19 regulatory period. This is because to roll-forward the RAB we have used the March CPI series for the eight capital cities (also published by the ABS), in accordance with the Utilities Commission Determination for the price control formula for that period.

9.2	Provide, in *Workbook 1 – regulatory determination, regulatory template* 2.14, the labour and material price changes assumed by *PWC* in estimating *PWC's forecast capex* proposal and the forecast *opex* proposal. All price changes must be expressed in percentage year on year real terms.	Please refer to "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11) and "Reset RIN Population Model"(Attachment 11.16). These are also repeated in "SCS opex model" (Attachment 12.4) and "ACS metering opex model" (Attachment 12.5).
9.3	Provide:	
9.3(a)	the model(s) used to derive and apply the materials price changes, including model(s) developed by a third party;	We are not proposing any (real) materials escalators, and so have not relied on any models to derive or apply them. Rather, we are proposing that the cost of materials escalates will be consistent with forecast inflation.
9.3(b)	in relation to labour escalators, a copy of the current Enterprise Bargaining Agreement or equivalent agreement; and	Please see "Power and Water Enterprise Agreement: 2015-2018" (Attachment 10.7).
9.3(c)	documents supporting or relied upon that accurately explain the change in the price of goods and services purchased by *PWC*, including evidence that any materials price forecasting method explains the price of materials previously purchased by *PWC*.	As noted in response to 9.3(a), we are not proposing any (real) materials escalators. This means that we have not developed or relied upon any documents to support material escalators, including any that explain the change in price of goods and services that we purchase.
9.4	Provide also an explanation of :	

9.4(a)	the methodology underlying the calculation of each price change, including:	We have relied on (real) labour cost escalator forecasts developed by BIS Shrapnel (BIS) and Deloitte Access Economics (DAE) reflected in reports relied on by the AER in its draft decision for ElectraNet in October 2017, and the final access arrangement determinations for the Victorian gas distribution networks in November 2017. We relied on the labour forecasts provided for South Australia, as it shares similar labour characteristics to the Northern Territory. Because both forecasts only extend to 2022-23, we estimated the real labour escalators for 2023-24 as the average of the respective forecasts for 2019-20 to 2022-23. The reports – listed below – explain the methodology, sources, and data conversions used to calculate the labour cost escalator forecasts. We were not provided and do not have access to the models used by either DAE or BIS to prepare their respective forecasts. • DAE, Labour Price Forecasts, Prepared for the Australian Energy Regulator, 6 February 2017, Table 7.1; which can be found on the AER's website at: https://www.aer.gov.au/system/files/Deloitte%20Access%20Economics%20-%20Labour%20price%20forecasts%20-%206%20February%202017.PDF • BIS, Report on expected wage changes to 2022-23, February 2017, Table 1, which can be found on the AER's website at: https://www.aer.gov.au/system/files/ElectraNet%20–%20ENET057%20–%20ElectraNet%20–%20BIS%20Shrapnel%20–%20Report%20on%20Expected%20Wage%20Changes%20to%202022_23%20–%20February%202017.pdf For both forecasts we used the wage price index measure. For the DEA forecast, we used the real escalator for the utilities industry, unadjusted for productivity. For the BIS forecast, we used the real escalator for the electricity, gas, water and waste services industry.
9.4(a)(i)	sources;	As noted above, these are explained in the reports from DAE and BIS.
9.4(a)(ii)	data conversions;	As noted above, these are explained in the reports from DAE and BIS.
9.4(a)(iii)	the operation of any model(s) provided under paragraph 9.3(a); and	As noted in response to 9.3(a), we have not used any model to derive and apply the materials price changes.
9.4(a)(iv)	the use of any assumptions such as lags or productivity gains;	We have applied no lags or productivity adjustments. As noted above, we have used the labour escalator forecasts, unadjusted for productivity. Any lags or other adjustments are explained in the respective reports from DAE and BIS.

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 price changes have been used in developing both the capex and opex forecasts. These are reflected in SCS opex model (Attachment 12.4), "ACS metering opex model" (Attachment 12.5) and "SCS and ACS Metering Forecast Capex Model" (Attachment 12.7).
9.4(c)	if the response to paragraph 9.4(b) is negative, why it is appropriate for different expenditure escalators to apply.	As noted in 9.4(b) above, we are proposing the same escalators for both forecast capex and opex.
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.	The current 2015-18 Enterprise Agreement has a nominal expiry date of 15 July 2018. Planning and preparation for negotiations for a replacement Enterprise Agreement is underway and alignment of Power and Water and the OCPE objectives is expected to be complete by end of January 2018. Formal negotiations expected to commence by end March 2018.
10	**OPERATING AND MAINTENANCE EXPENDITURE**	
10	**Total forecast operating and *maintenance* expenditure (*opex*)**	
10.1	Provide:	
10.1(a)	the model(s) and the methodology *PWC* used to develop total forecast *opex*;	We have provided the following models relevant to the way we developed total forecast opex for standard control services: • "SCS opex model" (Attachment 12.4) • "ACS metering model" (Attachment 12.5) • "Step changes forecast model" (Attachment 12.6) • "Spreadsheet for line length"(Attachment 12.8). The methodology underlying our total forecast opex is discussed in section 11.4 of our Regulatory Proposal document, and is supported by "Opex base year justification" (Attachment 3.1) and "SCS and ACS metering opex step changes" (Attachment 3.2).

10.1(b)	justification for *PWC*'s total forecast *opex*, including:	
10.1(b)(i)	why the proposed total forecast *opex* is required for *PWC* to achieve each of the objectives in clause 6.5.6(a) of the *NER*;	We have demonstrated how our total forecast opex achieves each of the objectives in 6.5.6(a) of the NT NER in the document "Addressing the Capex and Opex Objectives, Criteria and Factors in the NT NER" (Attachment 1.18).
10.1(b)(ii)	how *PWC's* total forecast *opex* reasonably reflects each of the criteria in clause 6.5.6(c) of the *NER*; and	We have demonstrated how our total forecast opex reasonably reflects each of the criteria in 6.5.6(c) of the NT NER in the document "Addressing the Capex and Opex Objectives, Criteria and Factors in the NT NER" (Attachment 1.18).
10.1(b)(iii)	how *PWC's* total forecast *opex* accounts for the factors in clause 6.5.6(e) of the *NER*;	We have demonstrated how our total forecast opex accounts for the factors in 6.5.6(e) of the NT NER in the document "Addressing the Capex and Opex Objectives, Criteria and Factors in the NT NER" (Attachment 1.18).
10.2	Provide:	
10.2(a)	the quantum of non-recurrent costs for each year of the *forthcoming regulatory control period*; and	We have not forecast any non-recurrent costs. We have used the opex forecast model typically used by the AER in its more recent regulatory decisions to apply the base step and trend method. In applying this method, we have: • Not included debt raising costs as these are separately accounted for – on a benchmark basis – in our proposed revenue models including "SCS Post Tax Revenue Model" (Attachment 12.1) and "ACS metering Post Tax Revenue Model" (Attachment 12.2). • Removed the value of guaranteed service level payments from base year opex and forecast these separately based on our expected costs, including for a step change in expected payments due to a change to the jurisdictional regulation that governs these payments. • Added step changes for changes in regulatory obligations, which are explained further in "SCS and ACS Opex Step Changes" (Attachment 3.2). We consider that each of these items are recurrent, and so have not forecast any non-recurrent costs for the 2019-24 regulatory control period.
10.2(b)	an explanation of each non-recurrent cost.	As per our response to 10.2(a), we have not forecast any non-recurrent costs.

10.3	If *PWC* used a revealed cost *base year* approach to develop its total forecast *opex* proposal, provide:	
10.3(a)	in Microsoft Excel format, reconciliation (including all calculations and formulae) of *PWC's* forecast total *opex* proposal to forecast *standard control services opex* by *opex* driver in *Workbook 1 – regulatory determination, regulatory template 2.16,* tables 2.16.1;	This is set out in Microsoft Excel form in "Reset RIN Population Model" (Attachment 11.16).
10.3(b)	the *base year PWC* used; and	As noted in section 11.5 of our regulatory proposal, we have used 2016-17 as the base year for forecasting opex in that proposal. We may reconsider revising this to 2017-18 as part of our revised regulatory proposal.
10.3(c)	explanation and justification for why that *base year* represents efficient and recurrent costs.	We have explained and justified this base year in Chapter 11 of our Regulatory Proposal document and in "Opex Base Year Justification" (Attachment 3.1). In summary, we have selected 2016-17 because it: • is the most recent full regulatory year of actual reported expenditure at the time of preparing our regulatory proposal; and • reflects the efficiencies that have been achieved in the current regulatory period, noting that our actual opex has reduced over the current regulatory period and is below, or in line with, the previous regulator's allowance.
10.4	If *PWC* does not use a revealed cost base year approach to develop its total forecast provide:	We confirm that we have used a revealed cost base year approach as set out in section 11 of our proposal. For this reason we have not provided a response to this question.
10.4(a)	forecast expenditure by *opex category* for each year of the *forthcoming regulatory control period* in *Workbook 1 – regulatory determination, regulatory template 2.16* for *standard control services opex* in table 2.16.2;	As stated in 10.4, Power and Water have used a revealed base year cost.

10.4(b)	in Microsoft Excel format, clear reconciliation (including all calculations and formulae) of *PWC*'s total forecast *opex* proposal to forecast *standard control services opex* by *opex category* in *Workbook 1 – regulatory determination, regulatory template 2.16,* table 2.16.2;	As stated in 10.4, Power and Water have used a revealed base year cost.
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;	As stated in 10.4, Power and Water have used a revealed base year cost.
10.4(d)	explanation and justification for:	As stated in 10.4, Power and Water have used a revealed base year cost.
10.4(d)(i)	whether *PWC* considers there is a year of historic *opex* that represents efficient and recurrent costs; or	As stated in 10.4, Power and Water have used a revealed base year cost.
10.4(d)(ii)	why *PWC* considers no year of historic *opex* represents efficient and recurrent costs.	As stated in 10.4, Power and Water have used a revealed base year cost.
10	**Output growth**	
10.5	Provide the amount of total forecast *opex* attributable to output growth changes for *standard control services opex* for each year of the *forthcoming regulatory control period* in *Workbook 1 – regulatory determination, regulatory template* 2.16, table 2.16.1.	We have completed template 2.16 in accordance with the AER's instructions as can be demonstrated in "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11) Table 2.16.1 was populated using "Reset RIN population model" (Attachment 11.16), which links to the models used to develop our output growth forecast in "SCS opex model" (Attachment 11.4) and "ACS metering opex model" (Attachment 12.5).
10.6	Provide:	

10.6(a)	the output growth drivers *PWC* used to develop the amount of total forecast *opex* attributable to output growth changes;	We have used customer numbers, circuit length, and ratcheted maximum demand drivers to forecast output growth. This is consistent with the method used by the AER in recent decisions for other distribution network service providers (DNSPs), such as the AER's final decisions for the Victorian DNSPs in May 2016. The drivers are combined in our forecast opex models in the "SCS opex model" (Attachment 12.4) and "ACS metering opex model (Attachment 12.5). The driver forecasts are sourced as follows: • Customer numbers – The source of the forecast is contained in "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4). • Circuit length – This has been forecast by extrapolating the historical relationship between capex and line length, and calculated in "Spreadsheet for line length (for rate of change)" (Attachment 12.8). • Ratcheted maximum demand – We have used the 50% POE forecast contained in "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4). These drivers are explained further in section 11.8 of Power and Water's Regulatory Proposal document.
10.6(b)	any economies of scale factors applied to the growth drivers;	Consistent with the method used by the AER in recent decisions, we have not applied any economies of scale factors to the growth drivers.
10.6(c)	evidence that the growth drivers explain cost changes due to output growth; and	As noted in section 11.8 of Power and Water's Regulatory Proposal, we have applied the output change measures and respective weightings that are detailed in the Economic Insights memo released with the AER's 2017 Annual Benchmarking Report. Our experience is that customer numbers impact the costs of providing services to customers. Circuit length impacts maintenance costs. Ratcheted maximum demand impacts augmentation capex, which in turn influences the level of maintenance opex. We rely on our experiences as a DNSP, and the modelling results from Economic Insights to support our proposed growth drivers.

10.6(d)	if *PWC* applied any composite multiple output growth drivers:	
10.6(d)(i)	the inputs for each composite multiple output growth driver; and	We did not apply any composite multiple output growth drivers. We have applied the output change measures and respective weightings that are detailed in the Economic Insights memo released with the AER's 2017 Annual Benchmarking Report.
10.6(d)(ii)	the weightings for each input.	We did not apply any composite multiple output growth drivers. We have applied the output change measures and respective weightings that are detailed in the Economic Insights memo released with the AER's 2017 Annual Benchmarking Report.
10.7	Provide an explanation of how, in developing the amount of total forecast *opex* attributable to output growth changes, *PWC*:	
10.7(a)	applied the output growth drivers; and	Section 11.8 of our regulatory proposal document identifies the weightings that we applied for each output growth input. These growth forecasts are applied to our proposed SCS and ACS metering opex forecasts via the following models - "SCS opex model" (Attachment 12.4) and "ACS metering opex model" (Attachment 12.5). In summary, we have applied the method reflected in the opex model typically used by the AER in recent decisions, which involves: • Forecasting the growth drivers. • Weighting these growth drivers in to a single output growth factor. • Combining this output growth factor with the forecast price change and productivity change factors to get a single opex rate of change. • Applying the single rate of change to base year opex. We have also provided the model underlying the application of output growth drivers to derive total forecast opex. Please see worksheet "Input – Rate of change" in "SCS Opex Model" (Attachment 12.4).

10.7(b)	accounted for economies of scale.	No economies of scale were explicitly applied when applying the output growth drivers. However, as explained below, we have relied on a zero productivity forecast as part of our overall rate of change, consistent with recent AER decisions. A zero forecast in part reflects the industry-wide productivity experienced over recent years, including from any economies of scale.
10	**Real price changes**	
10.8	Provide the amount of total forecast *opex* attributable to changes in the price of labour and materials for each year of the *forthcoming regulatory control period* for *standard control services opex* in *Workbook 1 – regulatory determination, regulatory template* 2.16, table 2.16.1.	We have completed template 2.16 in accordance with the AER's instructions as can be demonstrated in "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11).
10.9	Provide an explanation of:	

10.9(a)	how, in developing the amount of total forecast *opex* attributable to changes in the price of labour and materials, *PWC* applied the real price measures in *Workbook 1 – regulatory determination, regulatory template 2.14*; and	Section 11.7 of our regulatory proposal explains our method for developing the total amount of forecast opex attributable to changes in the prices of labour and materials. In summary, we: • Split the base year opex into labour and non-labour components using the weights (59.7%/40.3%) reflected in Economic Insights' memo to the AER's November 2017 Annual Benchmarking Report. • For the labour component, we used the labour escalators described in response to 9 above. • For the non-labour (i.e. materials) component, we assumed no real price changes. • Combined the real labour escalator with the (zero) real materials escalator and the assumed weights to get a single forecast price change factor. • Combined this price change factor with the forecast output growth and productivity change factors to get a single opex rate of change. • Applied the single rate of change to base year opex. This method was applied in the following models – "SCS opex model (Attachment 12.4) and "ACS metering opex model (Attachment 12.5).
10.9(b)	whether *PWC's* labour price measure compensates for any form of labour productivity change.	We have used a wages (or labour) price index. This does not directly factor in labour productivity. However, as discussed in section 11.5 of our Regulatory Proposal document, we have separately forecast opex efficiencies.

10	**Productivity change**	
10.10	Provide the amount of total forecast *opex* attributable to changes in productivity for *standard control services opex* for each year of the *forthcoming regulatory control period* in *Workbook 1 – regulatory determination, regulatory template* 2.16, table 2.16.1.	We have completed template 2.16 in accordance with the AER's instructions as can be demonstrated in "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11). This has been derived from data in "Reset RIN Population Model" (Attachment 11.16).

10.11	Provide, in percentage year on year terms, the productivity measure that *PWC* used to develop the amount of total forecast *opex* attributable to changes in productivity;	As noted in section 11.9 of our regulatory proposal, we have determined a rate of change productivity adjustment of zero per cent for each of the five years of the next regulatory period. This is reflected in "SCS opex model" (Attachment 12.4) and "ACS metering opex model (Attachment 12.5). This is consistent with recent AER decisions that have considered recent productivity trends and advice from Economic Insights. Although not necessarily related to annual productivity improvements, we propose a 10 per cent efficiency adjustment to base year opex. We anticipate that we will need to realise productivity and other efficiency gains over the 2019-24 to realise this. We discuss the efficiency adjustment further in section 11.5 of our regulatory proposal.
10.12	Provide an explanation of:	
10.12(a)	how, in developing the amount of total forecast *opex* attributable to changes in productivity, *PWC* applied the productivity measure in paragraph 10.11;	We have applied a zero per cent productivity adjustment "SCS opex model" (Attachment 12.4) and "ACS metering opex model" (Attachment 12.5) as can be seen in the "Input – Rate of change" worksheet in the models.
10.12(b)	whether *PWC*'s forecast productivity changes capture the historic trend of cost increases due to changes in *regulatory obligations or requirements* and industry best practice; and	As noted above, we have relied on the AER's recent decisions to support our zero per cent productivity adjustment. In making these decisions, that AER has considered the relationship between historical trends and changes in regulatory obligations or requirements and industry best practice. These decisions adopted a zero per cent productivity adjustment despite evidence showing that historical industry-wide productivity has been declining. In part, this is based on advice from Economic Insights that explains that some of observed decline is due to the impact of past step changes. Given this, adopting a value of zero as we have done would appear to adjust – at least notionally – for past changes in regulatory obligations or requirements and industry best practice.
10.12(c)	whether *PWC*'s productivity measure includes productivity change compensated for by the labour price measure used by *PWC* to forecast the change in the price of labour.	As noted in response to 10.12(b), our proposed zero per cent productivity adjustment is informed by historical industry productivity, which includes the impact from labour productivity. As per recent AER decisions, we propose combining a zero per cent productivity adjustment with WPI labour cost escalators to develop an opex forecast that fairly factors in labour and other productivity forecasts.
11	**STEP CHANGES**	

11.1	Provide the amount of total forecast *opex* attributable to *opex step changes* 1 for *standard control services opex* for each year of the *forthcoming regulatory control period* in *Workbook 1 – regulatory determination, regulatory template* 2.16, table 2.16.1.	We have completed template 2.16 in accordance with the AER's instructions as can be demonstrated in "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11). We have populated this template using data from the "Reset RIN population model)" (Attachment 11.16).
11.2	Provide an explanation of why *PWC* considers:	
11.2(a)	the efficient costs of the *step change* are not provided by other components of *PWC*'s total forecast *opex* such as base *opex*, output growth changes, real price changes or productivity change;	The costs of performing these new and additional responsibilities are currently not captured in the base year as explained in "SCS and ACS metering step changes" (Attachment 3.2). The nature of the cost is not reflected in output growth changes, or related to a price change or productivity change. As noted in response to 10.12(b), our proposed productivity adjustment reflects some adjustment to remove the effect of past step changes.
11.2(b)	the total forecast *opex* will not allow *PWC* to achieve the objectives in clause 6.5.6(a) of the *NER* unless the *step change* is included; and	Our proposed step changes relate to changes in our regulatory environment that are not captured in our base year costs for SCS and ACS metering opex. Without these step change we would not have sufficient funding to achieve the opex objective in 6.5.6(a)(2) of the NT NER to "comply with all applicable regulatory obligations or requirements associated with the provision of standard control services." We explain our step changes further in "SCS and ACS metering step changes" (Attachment 3.2).
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.	We have demonstrated that each step change relating to SCS (and ACS metering) represents the most prudent and efficient option to meet the changed regulatory obligation as demonstrated in "SCS and ACS metering opex step changes" (Attachment 3.2).
11.3	For all *step changes* in forecast expenditure (including those due to changes in *regulatory obligations or requirements* and those due to changes in *PWC*'s own *policies and strategies*) provide:	

11.3(a)	In *Workbook 1 – regulatory determination, regulatory template* 2.17 the quantum of the *step changes*:	We have completed template 2.17 in accordance with the AER's instructions as can be demonstrated in "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11). We have populated this template using data in "Reset RIN population model" (Attachment 11.16).
11.3(a)(i)	forecasts for each year of the *forthcoming regulatory control period*; and	We have completed template 2.17 in accordance with the AER's instructions as can be demonstrated in "Regulatory Determination Workbooks – Consolidated (Attachment 11.11). We have populated this template using data in "Reset RIN population model" (Attachment 11.16).
11.3(a)(ii)	expected to be incurred, in the *current regulatory control period*;	We have completed template 2.17 in accordance with the AER's instructions as can be demonstrated in "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11). We have populated this template using data in "Reset RIN population model" (Attachment 11.16).
11.3(b)	a description of the *step change.*	We have completed template 2.17 in accordance with the AER's instructions as can be demonstrated in "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11). The step change descriptions are further explained in "SCS and ACS metering step changes" (Attachment 3.2).
11.4	For each *step change* registered in response to paragraph 11.3, provide an explanation of:	
11.4(a)	when the change occurred, or is expected to occur;	The description of when each step change will occur is explained in "SCS and ACS metering step changes" (Attachment 3.2).
11.4(b)	what the driver of the *step change* is;	The description of the driver of each step change is explained in "SCS and ACS metering step changes" (Attachment 3.2).
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	The description of how the driver of the step change has or will change is explained in "SCS and ACS metering step changes" (Attachment 3.2).
11.4(d)	whether the *step change* is recurrent in nature.	The description of whether the step change is recurrent in nature is explained in "SCS and ACS metering step changes" (Attachment 3.2).
11.5	For each *step change* registered in response to paragraph 11.3, provide justification for when, and how, the *step change* affected, or is expected to affect:	

11.5(a)	the relevant *opex category*;	We have detailed the opex category under the title "classification of cost" in the document ""SCS and ACS metering step changes" (Attachment 3.2).
11.5(b)	the relevant *capex category*;	We have not identified any capex step changes. This is because we have not applied a forecasting method that uses step changes. As described in our responses to the capex questions above, we have used alternative methods to forecast capex categories that generally rely on bottom up assessments.
11.5(c)	total *opex*; and	We have explained the impact on total opex in "SCS and ACS metering step changes" (Attachment 3.2) with the resulting output captured in "Step changes forecast model"(Attachment 12.6). The step changes are combined with other components of our opex forecast to derive total forecast opex in "SCS opex model" (Attachment 12.4) and "ACS metering opex model" (Attachment 12.5).
11.5(d)	total *capex.*	As per our response to 11.5(b), we have not identified any capex step changes.
11.6	For each step change registered in response to paragraph 11.3, provide the process undertaken by *PWC* to identify and quantify the *step change*; provide cost benefit analysis that demonstrates *PWC* proposes to address the *step change* in a prudent and efficient manner, including:	We have outlined our process for quantifying the step change in "SCS and ACS metering step changes" (Attachment 3.2). In this document, we also outline the options we considered to determine the prudent and efficient expenditure related to the step change.
11.6(a)	the timing of the *step change*; and	The timing of the step change is provided in "SCS and ACS metering step changes" (Attachment 3.2), and supported by the profile of proposed expenditure in "Step change forecast model" (Attachment 12.6).
11.6(b)	if *PWC* considered a 'do nothing' option, evidence of how *PWC* assessed the risks of this option compared with other options.	We considered a range of options including the 'do nothing' option for each step change as demonstrated in "SCS and ACS metering step changes" (Attachment 3.2).
11.7	For each *step change* registered in response to paragraph 11.3, provide, if the *step change* is due to a change in a *regulatory obligation or requirement*:	We have identified the driver of each step change including whether it is driven by a regulatory change in the document "SCS and ACS metering step changes" (Attachment 3.2).

11.7(a)	any relevant variations or exemptions granted to *PWC* during the *previous regulatory control period* or the *current regulatory control period*; and	We have identified any relevant variation or exemptions in "SCS and ACS metering step changes" (Attachment 3.2).
11.7(b)	any relevant compliance *audits PWC* conducted during the *previous regulatory control period* or the *current regulatory control period.*	If relevant, we have identified if any compliance audits contribute to a step change in "SCS and ACS metering step changes" (Attachment 3.2).
11.8	For each *step change* registered in response to paragraph 11.7, provide, with reference to specific clauses of the relevant legislative instrument(s), the:	If relevant, we have referred to relevant legislative instruments underlying a step change in "SCS and ACS metering step changes" (Attachment 3.2).
11.8(a)	previous *regulatory obligation or requirement*; and	If relevant, we have identified previous regulatory obligations relating to a step change in "SCS and ACS metering step changes" (Attachment 3.2).
11.8(b)	how the changed *regulatory obligation or requirement* is driving the *step change*.	If relevant, we have shown how changes in regulatory obligations will drive a step change in "SCS and ACS metering step changes" (Attachment 3.2)

11	**Category specific opex**	
11.9	Provide the amount of total forecast *opex* attributable to category specific *opex* for each year of the *forthcoming regulatory control period* in *Workbook 1 – regulatory determination*, table 2.17.5. The amount of total *opex* attributable to category specific *opex* must correspond with the category specific opex reported in table 2.16.1.	We have completed table 2.17.5 in accordance with the AER's instructions as can be demonstrated in "Regulatory Determination Workbooks – Consolidated (Attachment 11.11). We have populated this table using "Reset RIN population model" (Attachment 11.16).
12	**ECONOMIC BENCHMARKING REPORTING**	
12	**ECONOMIC BENCHMARKING**	

12.1	Complete the *Workbook 1 – regulatory determination, regulatory templates* (3.1 to 3.7) in accordance with:	Please refer to templates 3.1 to 3.7 in workbook 1 in "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11)
12.1(a)	Appendix E, Part C: Workbook 2 - Economic Benchmarking	When completing templates 3.1 to 3.7 in workbook 1 in "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11) we have reviewed the instructions in Appendix E as they relate to Part C of Workbook 2. The forecast/ estimate information has been prepared on a similar basis to actual information. We refer the AER to the "Basis of Preparation - Economic Benchmarking Template for 2005-06 to 2016-17" (Attachment 11.3) for our explanation of our methods and definitions for completing economic benchmarking information.
12.1(b)	paragraphs 12.2 to 12.10.	When completing templates 3.1 to 3.7 in workbook 1 in "Regulatory Determination Workbooks – Consolidated"(Attachment 11.11) we have reviewed the instructions in paragraphs 12.2 to 12.10. The forecast/ estimate information has been prepared on a similar basis to actual information. We refer the AER to the "Basis of Preparation - Economic Benchmarking Template for 2005-06 to 2016-17" (Attachment 11.3) for our explanation of our methods and definitions for completing economic benchmarking information.
12.2	The forecast revenue groupings in *Workbook 1 – regulatory determination, regulatory templates* 3.1.1 and 3.1.2 may be developed by trending forward actual historical revenue groupings in previous *regulatory years*. However:	
12.2(a)	Total revenues must equal the total forecast revenues proposed by *PWC* in its *regulatory proposal;* and	We can confirm that we have complied with the AER's instructions as the forecast revenue in template 3.1 in "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11) is consistent with forecast revenue in the regulatory proposal.
12.2(b)	Revenue groupings must reflect *PWC's* forecast demand for its services in the *forthcoming regulatory control period* in its *regulatory proposal*.	We can confirm that we have complied with the AER's instructions as the revenue groupings in template 3.1 in "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11) are consistent with forecast demand for services in the regulatory proposal.

12.3	Information provided in *Workbook 1 – regulatory determination, regulatory template 3.2, tables* 3.2.1 and 3.2.2 must reflect *PWC's cost allocation method*.	We can confirm that we have complied with the AER's instructions for template 3.2 in "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11) including that it reflects Power and Water's cost allocation method, which has previously been submitted to the AER.
12.4	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 forecast/ estimate information for template 3.7 (including trees) has been prepared on a similar basis to actual information. We refer the AER to the "Basis of Preparation - Economic Benchmarking Template for 2005-06 to 2016-17" (Attachment 11.3) for an explanation of our methods and definitions for completing economic benchmarking information, including where we have needed to estimate the data based on AER definitions.
12.5	In calculating responses to the *variables* DOEF0202 to DOEF0205, spans in the *network* service area where *PWC* is not responsible for the *vegetation management* associated with the span are not to be counted.	The forecast/ estimate information for template 3.7 (including spans) has been prepared on a similar basis to actual information. We refer the AER to the "Basis of Preparation - Economic Benchmarking Template for 2005-06 to 2016-17" (Attachment 11.3) for an explanation of our methods and definitions for completing economic benchmarking information, including where we have needed to estimate the data based on AER definitions.
12.6	"Total number of spans" (DOEF0205) includes service line spans.	The forecast/ estimate information for template 3.7 (including spans) has been prepared on a similar basis to actual information. We refer the AER to the "Basis of Preparation - Economic Benchmarking Template for 2005-06 to 2016-17" (Attachment 11.3) for an explanation of our methods and definitions for completing economic benchmarking information, including where we have needed to estimate the data based on AER definitions.
12.7	PWC 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).	The forecast/ estimate information for template 3.7 (including route line length) has been prepared on a similar basis to actual information. We refer the AER to the "Basis of Preparation - Economic Benchmarking Template for 2005-06 to 2016-17" (Attachment 11.3) for an explanation of our methods and definitions for completing economic benchmarking information, including where we have needed to estimate the data based on AER definitions.

12.8	For the purposes of calculating the "*Route line length*" *variable* (DOEF0301) or other *variables* measured in terms of *route line length*:	
12.8(a)	the length of service lines are not to be counted;	The forecast/ estimate information for template 3.7 (including length of service lines) has been prepared on a similar basis to actual information. We refer the AER to the "Basis of Preparation - Economic Benchmarking Template for 2005-06 to 2016-17" (Attachment 11.3) for an explanation of our methods and definitions for completing economic benchmarking information, including where we have needed to estimate the data based on AER definitions.
12.8(b)	the length of a span that shares multiple *voltage* levels is only to be counted once;	The forecast/ estimate information for template 3.7 (including length of a span) has been prepared on a similar basis to actual information. We refer the AER to the "Basis of Preparation - Economic Benchmarking Template for 2005-06 to 2016-17" (Attachment 11.3) for an explanation of our methods and definitions for completing economic benchmarking information, including where we have needed to estimate the data based on AER definitions.
12.8(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.	The forecast/ estimate information for template 3.7 (including lengths of 2 sets of lines) has been prepared on a similar basis to actual information. We refer the AER to the "Basis of Preparation - Economic Benchmarking Template for 2005-06 to 2016-17" (Attachment 11.3) for an explanation of our methods and definitions for completing economic benchmarking information, including where we have needed to estimate the data based on AER definitions.
12.9	All forecast *variables* in the *Workbook 1 – regulatory determination, regulatory templates* (3.1 to 3.7) must align with those in *PWC's regulatory proposal*. For the avoidance of doubt this includes forecast:	
12.9(a)	opex and *capex*;	The opex and capex reported in templates 3.3 and 3.4 of "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11) are consistent with the documents submitted as part of our regulatory proposal.

12.9(b)	maximum demand and *energy delivery*;	The maximum demand and energy delivery in templates 3.3 and 3.4 of "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11) are consistent with the documents submitted as part of our regulatory proposal.
12.9(c)	revenues;	The revenues in template 3.1 of "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11) are consistent with the documents submitted as part of our regulatory proposal.
12.9(d)	quality of services *variables* including *SAIDI* and *SAIFI*; and	The quality of services variables in template 3.6 of "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11) is consistent with the documents submitted as part of our regulatory proposal.
12.9(e)	quantities of physical *assets*.	The quantities of services variables in template 3.6 of "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11) are consistent with the documents submitted as part of our regulatory proposal.
12.10	RAB *asset* financial data in the *Workbook 1 – regulatory determination, 3.3 Assets* (*RAB*) *regulatory template* must reconcile to that in *PWC*'s *regulatory proposal* PTRM and RFM.	The RAB asset financial data in template 3.3 of "Regulatory Determination Workbooks – Consolidated" (Attachment 11.11) is consistent with the documents submitted as part of our regulatory proposal.
13	**ALTERNATIVE CONTROL SERVICES REPORTING**	
13	**ALTERNATIVE CONTROL SERVICES**	
13.1	The *overheads* relating to each *alternative control service* must be disclosed in accordance with paragraph 13.2.	We have outlined the overheads for fee and quoted alternative control services in the worksheet "Calc Sheet Latest and Quoted services" in the model "ACS - Input Charges (Fee-based Services - Handbook, Information sheet, Tariff model)"(Attachment 12.18). We have separately identified the overhead component related to the provision of the Type 1 to Type 6 metering services. This is set out in Attachment 12.5 (ACS Metering Opex Model). Our methodology for deriving the overhead component of each service from our audited accounts for the 2016-17 base year is found in Appendix A to C of our "Basis of Preparation for the Category RIN" (Attachment 11.2).

13.2	Provide a register of all of the *alternative control services* that *PWC* intends to provide to *customers* and levy charges for in the *forthcoming regulatory control period*.	We provide a register of each fee and quoted alternative control service that we intend to provide customers in Section 19.2 of Power and Water’s Regulatory Proposal document (“Fee based & Quoted Alternative Control Services”). Section 7 of the document “Tariff Structure Statement” (Attachment 2.1) provides a register of each applicable charge relating to the provision of Type 1 to Type 6 metering services for the forthcoming period.
13.3	Provide a definition of each *alternative control service* registered in paragraphs 14 and 15.	We have provided a definition of each fee and quoted alternative control service in Section 19.2 of Power and Water’s Regulatory Proposal document (“Fee based & Quoted Alternative Control Services”). We have defined the provision of Type 1 to Type 6 metering services in section 2 of the document “Alternative Control Services - Metering Overview Document - 2019-20 to 2023-24” (Attachment 9.1) that accompanies our regulatory proposal.
13.4	For each *alternative control service* registered in paragraphs 14 and 15, 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*.	We have outlined the fee based and quoted charges for each alternative control services in the current regulatory period in the document "ACS table of revenues and fees for the current and forthcoming period” (Attachment 9.2). Please note that there were no charges relating to Type 1 to Type 6 metering services in the current period as this was a standard control service without a discreet charge. We have outlined indicative charges for each year of the forthcoming regulatory period for each alternative control service (fee based, quoted and Type 1 to 6 metering services) in Appendix A of the “Tariff Structure Statement” (Attachment 2.1).
13.5	For each *alternative control service* registered in paragraphs 14 and 15, specify the total revenue earned by *PWC* in each year of the *current regulatory control period and forthcoming regulatory control period*.	We have outlined the total revenue earned by PWC in each year for fee based and quoted ACS service in the current and forthcoming regulatory period in the document “ACS table of revenues and fees for the current and forthcoming period” (Attachment 9.2). We have identified the revenues for Type 1 to 6 metering service in section 6 of the document “Alternative Control Services - Metering Overview Document - 2019-20 to 2023-24” (Attachment 9.1) that accompanies our regulatory proposal. Please note that there was no specified revenue collected from customers relating to the provision of Type 1 to Type 6 metering services in the current period, as this was a standard control service.

13.6	For each *alternative control service* registered in paragraphs 14 and 15, provide the labour rate(s) used to calculate the charges for the *current* and *forthcoming regulatory control periods:*	We have outlined the labour rate(s) of the charge for each fee based and quoted alternative control service in the tab "Calc Sheet Latest and Quoted services" in the model "ACS - Input Charges (Fee-based Services - Handbook, Information sheet, Tariff model)" (Attachment 12.18). We have specified the labour rate for installation of new meters in the tab "Input meters" in the model "ACS Metering - CBA Model" (Attachment 12.19) at cells P60 to R60.
13.6(a)	specify the *labour classification level* used to provide the services e.g. outsourced or internally provided and labourer type;	We have specified the labour classification level used to provide each alternative control services in the tab "Calc Sheet Latest and Quoted services" in the model "ACS - Input Charges (Fee-based Services - Handbook, Information sheet, Tariff model)" (Attachment 12.18). We have assumed that both internal and external labour to install meters and undertake operating activities would require the following skill set "Technical Specialist, Trade Technical and Operator".
13.6(b)	register all *direct costs*, and their quantum, in the make-up of the labour rate(s).	We have specified the direct costs, and their quantum in the make-up of the labour rates. This can be seen in "Calc Sheet Latest and Quoted services" in the model "ACS - Input Charges (Fee-based Services - Handbook, Information sheet, Tariff model)" (Attachment 12.18). The labour rates included in the tab "Input meters" in the model "ACS Metering - CBA Model" (Attachment 12.19) are direct, but include on-costs directly related to staff.
13.7	Register each material category (e.g. *meters*, *poles*, brackets) required for the provision of *alternative control services* registered in the response to paragraphs 14 and 15.	For quoted and fee services, the only identified material costs relate to metering equipment for customer initiated metering services. For quoted services, the material cost is dependent on the activity performed, and therefore there is no set schedule of material costs. For Type 1 to Type 6 meters, we have identified the capital cost of a smart meter for new and replacement capex in the worksheet "Input meters" in the model "ACS Metering - CBA Model" (Attachment 12.19). We have also included the cost of modem, antenna and communications for existing meters in the same tab.
13.7(a)	provide a description of each material category;	For fee-based services, the only identified material costs relate to the meter. For Type 1 to Type 6 meters, we will be installing advanced meters supported by the necessary IT communications to give effect to remote reading and remote re-energisation and de-energisation. We will also be installing modems, antenna and communications consistent with modern technology.

13.7(b)	provide the *average unit costs* for each material category;	With the exception of meters, there is no other relevant material cost such as brackets and poles etc for any fee-based services. For quoted services, the material cost is dependent on the activity performed, and therefore there is no set schedule of material costs. For Type 1 to Type 6 meters, we have identified the capital cost of a smart meter for new and replacement capex in the worksheet "Input meters" in the model "ACS Metering - CBA Model" (Attachment 12.19) at cell J60. We have also included the cost of modem, antenna and communications for existing meters in the same tab.
13.7(c)	register all *direct costs* included in the unit costs;	With the exception of meters, there is no other relevant material cost such as brackets and poles etc for any fee-based services. We have separated the direct cost of the meter from other indirect costs. For quoted services, the material cost is dependent on the activity performed, and therefore there is no set schedule of material costs. For Type 1 to 6 meters, we have separated out the direct equipment cost from the installation cost. This can be seen in the worksheet "Input meters" in the model "ACS Metering - CBA Model" (Attachment 12.19).
13.7(d)	specify the calculation of the quantum of *direct materials costs* included in the unit cost of materials.	With the exception of meters, there is no other relevant material cost for any fee-based services. For quoted services, the material cost is dependent on the activity performed, and therefore there is no set schedule of material costs. The quantum for each fee based service is provided in the worksheet "Input meters" in the model "ACS Metering - CBA Model" (Attachment 12.19). For Type 1 to 6 meters, we have separated out the direct equipment cost from the installation cost. This can be seen in the tab "Input meters" in the model "ACS Metering - CBA Model" (Attachment 12.19)
14	**FEE BASED AND QUOTED ALTERNATIVE CONTROL SERVICES**	
14.1	Provide a description of each *fee based* and *quoted service*, explaining the purpose of the service and register the activities which comprise each service.	We have provided a description of each fee based and quoted service in section 19.2 of Power and Water's Regulatory Proposal document ("Fee based & Quoted Alternative Control Services"), which explains the nature, and purpose of the service provided to customers. We note that customer initiated metering services are included as part of our fee based services, and therefore have been addressed in this section.
14.1(a)	specify if the charges are for *fee based* and/or quoted *alternative control services*;	We have identified fee-based services in section 19.2 of Power and Water's Regulatory Proposal document ("Fee based & Quoted Alternative Control Services"), while quoted services are identified in section 19.3.

14.1(b)	explain the reasons for the different charge with reference to the costs incurred;	Section 19.2 and 19.3 of Power and Water's regulatory proposal explains the reasoning for the distinction between charging on a quoted and fee basis. Fee based services are generally predictable in scope and do not vary greatly with the project. In contrast, quoted services depend on the scope of a customer's request. It is not practical to establish individual fees for quoted services as the costs vary significantly on a project-by-project basis.
14.1(c)	explain the method used to set the different charge; and	Section 19.2 and 19.3 of Power and Water's regulatory proposal set out the underlying basis for our method to determine quoted and fee based services. Our fee-based services use a bottom-up, input cost model to determine the efficient, cost-reflective charge for each individual service. Our quoted services are based on labour rates per hour (including on-costs and overheads) with materials, contractor and other costs reflecting the costs involved with the specific project.
14.1(d)	provide the calculations underpinning the different charge.	We have outlined the calculations for each alternative control services in the worksheet "Calc Sheet" in the model "ACS - Input Charges (Fee-based Services - Handbook, Information sheet, Tariff model)" (Attachment 12.18).
14.2	Identify the tasks involved in providing the service in *Workbook 1 – regulatory determination, regulatory templates* 4.3 and 4.4:	We have itemised cost components to complete the task in the tab "Calc Sheet" in the model "ACS - Input Charges (Fee-based Services - Handbook, Information sheet, Tariff model)" (Attachment 12.18).
14.2(a)	map the class of labour required to provide the service registered in *regulatory templates* 4.3 and 4.4;	For each service, we have applied a labour rate for the technical skill that aligns with the task to be performed in providing the service. This is provided in the worksheet "Calc Sheet" in the model "ACS - Input Charges (Fee-based Services - Handbook, Information sheet, Tariff model)" (Attachment 12.18). We have considered three broad labour classes skills that would apply to the service including: • Administration • Technical specialist, trade technical and operator • Engineering.
14.2(b)	the number of workers required to undertake the task and deliver the service;	For fee-based services, we have identified the number of workers required to undertake and deliver the service as part of our build-up of costs relating to the service. This is set out in "Calc Sheet" in the model "ACS - Input Charges (Fee-based Services - Handbook, Information sheet, Tariff model" (Attachment 12.18). The number of workers for quoted services will vary dependent on the project.

14.2(c)	the *average* time required to complete the task and deliver the service.	For fee-based services, we have identified the number of hours required to undertake and deliver the service as part of our build-up of costs relating to the service. This is set out in the worksheet "Calc Sheet" in the model "ACS - Input Charges (Fee-based Services - Handbook, Information sheet, Tariff model)" (Attachment 12.18). The average time for quoted services will vary dependent on the project.
14.3	If materials are required to provide the service, specify each material category.	With the exception of meters, there is no other relevant material cost such as brackets and poles etc for any fee-based services. The cost of the meter is set out in the worksheet "Calc Sheet" in the model "ACS - Input Charges (Fee-based Services - Handbook, Information sheet, Tariff model)" (Attachment 12.18). For quoted services, the material cost is dependent on the activity performed, and therefore there is no set schedule of material costs.
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*.	We have outlined the fee based and quoted charges for each alternative control services in the current regulatory period in the document ""ACS table of revenues and fees for the current and forthcoming period" (Attachment 9.2) that accompanies this regulatory proposal. We have identified the charges (or basis of charge) for each alternative control service in the forthcoming period in the tabs "Appendix 1 Fee Based" and "Appendix 2 Quoted" in the model "ACS - Input Charges (Fee-based Services - Handbook, Information sheet, Tariff model)" (Attachment 12.18).
15	**METERING ALTERNATIVE CONTROL SERVICES**	
15.1	For regulated *metering services* for types 1,2,3,4,5 and 6, for the *current regulatory control period* and the *forthcoming regulatory control period*, provide details of the:	In addressing Question 15 of Schedule 1 of the RIN, we have defined metering alternative control services as only relating to the provision of Type 1 to 6 metering services. Customer requested meter-related services are part of our fee-based services discussed in Question 14 above.

15.1(a)	direct materials and *direct labour costs*;	The direct material costs include the costs of the meter, and other equipment associated with the meter such as the modem, antenna and communications. For the current period, please refer to our description of template 4.2 of "Basis of Preparation - Category Analysis Template for 2008-09 to 2016-17" (Attachment 11.2) for an explanation of expenditure categorisation. For the forthcoming period, we have identified the capital cost of a smart meter for new and replacement capex in the tab "Input meters" in the model "ACS Metering - CBA Model"(Attachment 12.19). We have also set out the cost of a modem, antenna and communications for existing meters in the same tab, together with the labour costs involved in installing smart meters. Please note that forecast metering opex applies a base-step-trend approach, and therefore we have used historical opex as a basis for our forecasts.
15.1(b)	installation costs;	For the current period, please refer to template 4.2 of "Basis of Preparation - Category Analysis Template for 2008-09 to 2016-17" (Attachment 11.2) for a description of our process for capturing the expenditure associated with installation. For the forthcoming period we have identified the installation costs of the preferred smart meter in the worksheet "Input meters" in the model "ACS Metering - CBA Model" (Attachment 12.19). The estimated costs reflect historical experience.
15.1(c)	meter purchase costs;	For the current period, please refer to template 4.2 of "Basis of Preparation - Category Analysis Template for 2008-09 to 2016-17"(Attachment 11.2) for a description of our process for capturing the meter purchase costs. For the forthcoming period, we have identified the cost of our preferred smart meter technology in the tab "Input meters" in the model "ACS Metering - CBA Model" (Attachment 12.19) that accompanies our regulatory proposal. The model identifies the raw meter cost, and the "plug in" option required to install the asset. The purchase cost is based on our estimate of current costs after discussions with suppliers.
15.1(d)	volumes of work;	We have defined volumes of work as meters added or replaced. In the current period please refer to our description of template 4.2 of "Basis of Preparation - Category Analysis Template for 2008-09 to 2016-17" (Attachment 11.2) Our volumes for the forthcoming period are based on an estimate of new customer connections and replacement of meters at the end of their useful life. This is described in section 5.2 of the document "Alternative Control Services - Metering Overview Document - 2019-20 to 2023-24"(Attachment 9.1).

15.1(e)	other costs associated with providing *metering services*;	For a description of actual costs in the current period please refer to our description of template 4.2 of "Basis of Preparation - Category Analysis Template for 2008-09 to 2016-17" (Attachment 11.2). Our forecast capex for the forthcoming period comprises upgrading existing advanced capable meters with modems and antennae to convert them to advanced meters, upgrading the communications capability of our existing advanced meters from 3G to 4G technology, and non-network capex associated with fleet, property, equipment. A more detailed description can be found in section 5.2 of the document "Alternative Control Services - Metering Overview Document - 2019-20 to 2023-24" (Attachment 9.1). We have used a base step trend (BST) approach to forecast our opex for the 2019-24 regulatory period. A BST approach involves forecasting our opex at an aggregate level, rather than preparing individual forecasts for each category of opex. Further information on our approach can be found in section 5.3 of the document "Alternative Control Services - Metering Overview Document - 2019-20 to 2023-24"(Attachment 9.1)
15.1(f)	type of *meters* installed and forecast to be installed, separately for new meters and for replacement *meter*s;	Our description of 4.2 of "Basis of Preparation - Category Analysis Template for 2008-09 to 2016-17" (Attachment 11.2) identifies the Meter Types we have installed in the current period, including a breakdown by replacement and new meters. Section 4 of the document "Alternative Control Services - Metering Overview Document - 2019-20 to 2023-24" (Attachment 9.1) notes that we intend to install advanced meters in the forthcoming period. The meters will be supported by the necessary IT communications to give effect to remote reading and remote re-energisation and de-energisation. The document also identifies that we will add or replace between 5,300 to 5,700 advanced meters per annum in the forthcoming period. The detailed breakdown of new and replacement meters can be found in the worksheet 'Input Meter Movements' in the model "ACS Metering - CBA Model" (Attachment 12.19).
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	Metering was a standard control service in the current period so no specific revenue was collected based on meter type. The forecast revenue by 1 phase, 3 phase, and dedicated CT and VT meters for each regulatory year in the forthcoming period is set out in the tab "Forecast revenues" in the model "ACS Metering Post-tax Revenue Model"(Attachment 12.2).

15.1(h)	the total operating and *maintenance* costs incurred, and forecast to be incurred, for *metering services*.	The actual opex associated with metering costs in the current period is provided in table 2.1.2 of the tab "Expenditure summary" in "Category Analysis RIN Workbooks – Consolidated" (Attachment 11.5). The forecast opex (including debt raising costs) for metering services is found in Table 6.1 of the document "Alternative Control Services - Metering Overview Document - 2019-20 to 2023-24" (Attachment 9.1).
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;	The activities for the current and forthcoming periods are of a similar nature, but may vary in scope and magnitude as a result of meter technology changes, and new obligations imposed in our regulatory framework. The type of work includes the following: • Meter purchase – this involves purchasing meters that meet the specifications required to provide a metering service in an efficient manner. • Meter inspection and testing – this involves testing the functionality of each new meter purchased, together with inspections and testing of the meters in service. In the current regulatory period, we undertook testing of newly purchased meters to ensure that they were operating properly. However we had no obligation to undertake routine testing of the meters in service, and therefore did not perform that activity. Under the new compliance obligations in the NT NER, we will now have an obligation to undertake routine inspection and metering. The additional requirements and costs for the forthcoming period are explained in more detail in the document "SCS and ACS opex step changes" (Attachment 3.2). • Meter installation – this involves installing a purchased meter in the premises of a customer. The nature of this activity can vary with the type of meter that is being installed, and the installation type. • Meter reading– This involves reading of meters manually or remotely for the purpose of accurate billing of our customers. As explained in "SCS and ACS opex step changes" (Attachment 3.2), the change in our meter technology (advanced meters) over the forthcoming period will mean the nature of the activity will change in the forthcoming period. For example, we will need to incur additional expenditure on communications to enable remote reading of meter data, but our manual costs of meter reading will fall. • Meter data services – this involves collection, processing, management, delivery and storage of metering data. • Administration and training – these are the costs involved in ensuring that we have sufficiently skilled labour to perform our metering activities, and that we provide an efficient metering service overall.

15.2(b)	the *labour costs* involved in providing the service, including any *overheads*;	The labour costs relate to metering installation, meter reading (excluding the data communication costs), meter inspection and testing, and administration and training. We also allocate overheads to metering services in accordance with the Cost Allocation Method, and some of this may relate to labour hours. This would include labour costs for administration and training, together with the labour costs of Information and Communication Technology. It should be noted that some of the labour costs relate to external providers.
15.2(c)	any materials costs involved in providing the service;	The material costs primarily relate to the purchase of the meter.
15.2(d)	the number (volume) of services provided and associated assumptions on which the volume of service was derived or estimated;	For actual volumes (that is, meters added or replaced) in the current period please refer to our description of template 4.2 of "Basis of Preparation - Category Analysis Template for 2008-09 to 2016-17" (Attachment 11.2) Our volumes for the forthcoming period are based on an estimate of new customer connections and replacement of meters at the end of their useful life. This is described in section 5.2 of the document "Alternative Control Services - Metering Overview Document - 2019-20 to 2023-24"(Attachment 9.1).
15.2(e)	the charge per service; and	In the current period, metering services were a standard control service. As such, there was no specific charge per service. For the forthcoming period, we are proposing a simple schedule of three metering service provision charges. The charge is based on whether the customer has a single-phase meter, three phase meter or dedicated current transformer or voltage transformer with remote reading (CT and VT meters). We considered that further disaggregation was not warranted because the pricing outcomes were materially similar and would not justify the additional costs of disaggregation. Our method involves allocating a proportion of the forecast revenue to each service, based on the relative difference in servicing each type of meter. We identify and describe the charge in section 7 of the document "Alternative Control Services - Metering Overview Document - 2019-20 to 2023-24" (Attachment 9.1).
15.2(f)	the revenue earned by each service.	We have adopted a building block approach to determining our revenue requirements for our ACS Metering Services, consistent with that applied to determining our SCS revenue requirements. Further details are provided in Section 6 of the document "Alternative Control Services - Metering Overview Document - 2019-20 to 2023-24" (Attachment 9.1)". As discussed in section 12.2(e) above, the total revenue was then disaggregated into each of the three service charge elements based on the relative difference in servicing each type of meter.

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*.	For the current period, we have provided actual customer numbers for 2014-15 to 2016-17 in the current tab "3.4 –Operational Data" in "Economic Benchmarking RIN Workbooks – Consolidated" (Attachment 11.8), with estimated customer numbers for 2017-18 in the equivalent tab of "Regulatory Determination Workbooks –Consolidated" (Attachment 11.11). We have noted which customers do not have meters. We have provided the forecasts of customer numbers for single-phase meter, three-phase meter or dedicated current transformer or voltage transformer with remote reading (CT and VT meters) for 2018-19 to 2023-24 in the worksheet "PTRM Inputs" in "ACS Metering Post-tax Revenue Model" (Attachment 12.2).
16	**NETWORK INFORMATION REPORTING**	
16	**DEMAND AND CONNECTIONS FORECASTS**	
16.1	Provide and describe the methodology used to prepare the following forecasts for the *forthcoming regulatory control period*:	
16.1(a)	maximum demand; and	The methodology for maximum demand forecasts were prepared by AEMO, and are contained in Appendix A.3 and A.4 of the Document: "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4). Further detailed information is contained in the document "Maximum demand and customer connections forecasting procedure" (Attachment 4.5).
16.1(b)	number of new *connections*.	The methodology for connection forecasts were prepared by AEMO, and are contained in Appendix A.1 of the document: "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Appendix 4.4).
16.2	Provide:	
16.2(a)	the model(s) *PWC* used to forecast new *connections* and *maximum demand*;	We have relied on modelling provided by AEMO for connections and maximum demand. AEMO owns the intellectual property of the model, and therefore only provides us with the outputs and methodology.

16.2(b)	where *PWC*'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 *PWC's* current approach. If any of this data is unavailable, explain why;	We have provided actual data based on our approach to weather correction in the past. Demand forecast information has been based on AEMO modelling and suggested procedures, which involves a different method for weather correction. We have not been able to accurately backcast AEMO's weather correction method to our historical data in the time we had available.
16.2(c)	for number of new *connections*, volume data requested in *Workbook 1 – regulatory determination, regulatory template 2.5*; and	We have provided this information in accordance with the AER's instructions in template 2.5 of "Category Analysis RIN Workbooks – Consolidated" (Attachment 11.5).
16.2(d)	any supporting information or calculations that illustrate how information extracted from *PWC*'s forecasting model(s) reconciles to, and explains any differences from, information provided in *Workbook 1 – regulatory determination, regulatory templates 2.5, 3.4 and 5.4*.	This information is contained in Appendix A.4 of "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4). AEMO undertook additional work to produce a Northern Territory system peak, when the three power systems peak at different times. The resulting modelling resulted in a Northern Territory wide peak that was closely aligned to that of Darwin and Katherine.
16.3	For each of the methodologies provided and described in response to paragraph 16.1, and, where relevant, data requested under paragraphs 16.2(b) and 16.2(c), explain or provide (as appropriate):	
16.3(a)	the models used;	The methods, assumptions and data sources used in the modelling for customer connections, energy forecasts, regional demand forecasts and zone substation maximum demand forecasts are set out in Appendix A.1 to A.4 of "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4). As noted in 16.2 above, we have not been provided the model that AEMO has used to forecast demand for intellectual property reasons.

16.3(b)	a global[1] (top-down) and spatial[2] (bottom-up) demand forecast;	AEMO developed regional demand forecasts for each of Power and Water's three stand-alone networks, and also developed spatial demand forecasts. Further, AEMO modelled a Power and Water global forecast for the whole network. This is further discussed in Appendix A.3 and A.4 of the document "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4).
16.3(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);	The inputs and assumptions used in the modelling for customer connections, energy forecasts, regional demand forecasts and zone substation maximum demand forecasts are set out in Appendix A.1 to A.4 of "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4).
16.3(d)	the *weather correction* methodology, how weather data has been used, and how *PWC*'s approach to *weather correction* has changed over time;	The weather correction methodology used for our demand forecasts is outlined in Appendix A.3 and A.4 of "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4). There are differences between the approach AEMO has undertaken for weather correction relative to the approach we have undertaken in the past, and which forms the basis of our response to the historical data in the category RIN. In the past we had been targeting our POE calculations on the weather rather than the load. We accept that the method incorporated by AEMO for our demand forecasts is a more accurate method.
16.3(e)	an outline of the treatment of *block loads, transfers* and *switching* within the forecasting process;	AEMO discuss how it has incorporated block loads, transfers and switching into its demand forecasts at Appendix A.3 and Appendix A.4 of "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4). For clarity, block loads, transfers and switching is also applied to high voltage feeders. In summary, AEMO applied block loads, transfers, and switching periods in the forecast if they were categorised as committed. These were applied as post-model adjustments to the zone substation maximum demand forecasts. Typically, these changes were in units of MVA, and were therefore converted to MW using a power factor obtained from historical data. The block loads, transfers, and switching included in the forecasts are summarised in Appendix G of Attachment 4.4.

16.3(f)	each appliance model[3] used, where used, or assumptions relating to average customer energy usage (by customer type);	Our energy forecasting process did not apply an appliance model approach. Our approach for deriving energy forecasts is explained in Appendix A.1 of "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4). In summary we used a weather-based regression model built from daily system consumption data, correlated against weather data from weather stations in close proximity to demand centres. This model was then used to create a 'base year' forecast. The base forecast year assumes median weather data to capture seasonal effects in electricity consumption. The forecast was then grown on an annual basis, applying both positive (such as connections growth) and negative demand drivers (such as rooftop PV).
16.3(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*);	Appendix A.1 to A.4 of "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4) makes clear that historical observations of energy, customer connections and maximum demand form the basis of our modelling approach. We have adopted AEMO's forecasting method as preferred to our previous method due to improved weather correction. For this reason we have not sought to test and challenge previous forecasting approaches.
16.3(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;	AEMO's approach has sought to reconcile forecasts between feeders, zone substations, sub-transmission substations and connection points. This is explained in Appendix A.1 to A.4 of "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4).
16.3(i)	how the forecasts resulting from these methods and assumptions have been used in determining the following:	
16.3(i)(i)	capex forecasts; and	The maximum demand forecasts have been a key input to developing our augmentation and connection programs. Specifically we have used spatial demand forecasts to determine whether there may be a constraint on a network as a result of peak demand growth.

16.3(i)(ii)	operating and *maintenance* expenditure forecasts.	Our opex model applies a "rate of change" forecast to determine opex in each regulatory year of the forthcoming period. The rate of change calculation uses customer number growth and maximum (ratcheted) demand forecasts.
16.3(j)	whether *PWC* used the forecasting model(s) it used in the joint planning process for the purposes of its *regulatory proposal*;	We do not undertake joint planning with a transmission provider due to the unique design of our electricity network in the Northern Territory. Our connection points relate to generation.
16.3(k)	whether *PWC's* 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);	Power and Water only forecasts non-coincident maximum demand at the feeder level. We forecast both non-coincident and coincident maximum demand at the connection point, sub-transmission substation and zone substations levels. AEMO have explained the manner in which they have reconciled to system level forecasts in Appendix A.4 of "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4). In summary, the non-coincident zone substation forecasts were reconciled to the relevant regional maximum demand forecast for each year in the 10-year forecast period. The reconciliation process also produced coincident zone substation forecasts in MW, starting from an unreconciled estimate of coincident demand. This was based on diversity factors representing the ratio of coincident-to-non-coincident maximum demand at the zone substation.
16.3(l)	whether *PWC* records historic *maximum demand* in *MW*, *MVA* or both;	We record MW and MVA at connection points, sub-transmission, and zone substations. We only record amps for high voltage feeders, as we do not record voltage or power factor correction at this level of the network. For high voltage feeders we assume normal voltage to provide and estimated MVA value.
16.3(m)	the *probability of exceedance* that *PWC* uses in *network planning*;	We use 50% POE for all elements of network, with the exception of high voltage feeders and distribution substations where we use raw data.
16.3(n)	the contingency planning process, in particular the process used to assess high system demand;	Our network criteria for investment are identified in the document "Network Technical Code and Network Planning Criteria" (Attachment 4.2). The Code sets out the contingency/ redundancy at each level of the network, and is used to determine the timing of investment.

16.3(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;	Our approach to risk management for investment is discussed in section 4 of the document "Capex Overview Document" (Attachment 4.1).
16.3(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 *PWC's network*;	We note that our maximum demand forecasts were prepared by AEMO. We also do not have transmission network service providers due to the unique design of the electricity network in the Northern Territory. We have not identified any other source of comparison or reconciliation.
16.3(q)	how the normal and emergency ratings are used in determining capacity for individual *zone substations* and *sub-transmission lines*;	We use emergency ratings for our sub-transmission lines, but when planning the network we utilise the normal ratings to determine whether a constraint has occurred. This is due to the fact that sub-transmission lines only have a narrow window of time to operate at emergency rating before the asset is adversely impacted from over-heating. We use "contingency ratings" for our zone substations and sub transmission substations. For planning purposes, we assume these assets can operate above their normal rating as long as it does not exceed the aggregate thermal rating for the day.
16.3(r)	where *PWC* proposes to commence or continue a *demand-related capex project or program* during the *forthcoming regulatory control period* on a *HV feeder*:	
16.3(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:	We have not identified specific high voltage feeders in our proposed augmentation capex forecast. Rather we have developed an estimate of capex based on a modelling approach that relies on historical volumes, and spatial demand forecasts. This is due to the difficulty in identifying where a constraint will occur on the high voltage network well advance of it occurring. While we can identify locations of growth, constraints on the 11kV network are highly dependent on where new customers locate. Our annual planning process will identify specific feeders based on current information. In our responses below, we identify how that process works in practice.

16.3(r)(i)(A	assumed future load *transfers* between feeders;	As part of our annual planning process, we will update our demand forecasts consistent with our procedure as documented in "Maximum demand and customer connections forecasting procedure" (Attachment 4.5). This includes taking into account load transfers between feeders, which we log as part of this process.
16.3(r)(i)(B	assumed feeder underlying load growth rates (exclusive of *transfers* and specific *customer* developments); and	As discussed above this will be undertaken in accordance with our demand forecast procedure. We note that transfers and customer developments (i.e. block loads) are considered outside of the underlying growth forecast, and then included subsequently to the model.
16.3(r)(i)(C	assumed *block loads*, and associated demand assumptions;	As discussed above, block loads are considered as part of the demand forecast procedure.
16.3(r)(ii)	existing *embedded generation* capacity, and associated assumptions on the impact on demand levels;	This is captured through actual demand.
16.3(r)(iii)	assumed future *embedded generation* capacity, and associated assumptions on the impact on demand levels;	Our demand forecast process incorporates forecasts of household PV generation growth, and also considers the likely load injected into our network from potential embedded generation. We use a probabilistic approach to determining the likely capacity.
16.3(r)(iv)	existing non-network solutions, and the associated assumptions on the impact on demand levels;	Consistent with our demand management policy we will assess whether there are any viable and efficient non-network solutions to address the constraint on the network. At this stage of the planning process we have not identified any non-network solutions for the remainder of the current regulatory period or forthcoming regulatory period.
16.3(r)(v)	assumed future non-network solutions, and associated assumptions on the impact on demand levels; and	We will work with all parties to monitor whether there are any emerging non-network solutions that may become available in the future.
16.3(r)(vi)	the diversity between feeders.	As part of forecasting process record maximum demand on each feeder, and we may be able to see diversity in the commercial and residential feeder.
16.3(s)	where *PWC* 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*):	We have identified major augmentation projects in the current and forthcoming period in section 7 of the document "Capex Overview Document" (Attachment 4.1).

16.3(s)(i)	assumed future load *transfers* between related *substations*;	We have used AEMO's 10 year forecast to determine the constraints on our zone substations, substations, and sub-transmission lines. This includes consideration of future load transfers. Please see Appendix A.4 and A.7 of "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" for further information" (Attachment 4.1).
16.3(s)(ii)	assumed underlying load growth rates (exclusive of *transfers* and specific *customer* developments);	As noted above, we have relied on AEMO's 10 year forecast to determine the constraints on our zone substations, substations, and sub-transmission lines.
16.3(s)(iii)	assumed specific *customer* developments, and associated demand assumptions;	We note that AEMO's demand forecast incorporate specific customer developments. Further information can be found at Appendix A.4 of "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4).
16.3(s)(iv)	existing *embedded generation* capacity, and associated assumptions on the impact on demand levels;	AEMO's demand forecasts also incorporate existing embedded generation capacity. Further information can be found at Appendix A.4 of "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4).
16.3(s)(v)	assumed future *embedded generation* capacity, and associated assumptions on the impact on demand levels;	AEMO's demand forecasts also incorporate specific customer developments. Further information can be found at Appendix A.4 of "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4).
16.3(s)(vi)	existing non-network solutions, and the associated assumptions on the impact on demand levels;	Consistent with our demand management policy we will assess whether there are any viable and efficient non-network solutions to address the constraint on the network. At this stage of the planning process we have not identified any non-network solutions for the remainder of the current regulatory period or forthcoming regulatory period.
16.3(s)(vii)	assumed future non-network solutions, and associated assumptions on the impact on demand levels; and	We will work with all parties to monitor whether there will be any emerging non-network solutions that may become available in the future.
16.3(s)(viii)	diversity with related *substations*.	As part of forecasting process record maximum demand on each feeder, and we may be able to see diversity in the commercial and residential feeder.
16.4	Provide:	

16.4(a)	evidence that any independent verifier engaged by *PWC* 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	AEMO prepared the forecast. Given AEMO's expertise in demand forecasting, and their independence to our business, we believe this provides an independent verification of our demand forecasts.
16.4(b)	all documentation, analysis and models evidencing the results of the independent verification.	We have submitted all relevant documents available to us from AEMO.
17	**INCENTIVE SCHEMES AND OTHER REPORTING**	
17	**SERVICE TARGET PERFORMANCE INCENTIVE SCHEME**	
17.1	Provide *PWC*'s detailed methodology for calculating the following parameters used in the *STPIS*;	We have not departed from the AER's decision in the Framework and Approach paper not to apply a STPIS for the forthcoming period. Our proposed application of incentives schemes, including the non-application of the STPIS, is discussed in section 15 of Power and Water's regulatory proposal. To the extent that we have no scheme applying we have not addressed the questions on parameters that would have been used had the STPIS been applied.
17.1(a)	the *SAIDI*, *SAIFI* and *MAIFI* targets for each supply reliability area;	See our response to 17.1 above. We are not proposing to apply the STPIS.
17.1(b)	the *customer* service parameters and targets;	See our response to 17.1 above. We are not proposing to apply the STPIS.
17.1(c)	daily *SAIDI*, *SAIFI* and *MAIFI* and *customer* service performance derived from the individual *interruption* data under paragraph 17.2;	See our response to 17.1 above. We are not proposing to apply the STPIS.
17.1(d)	the *MED* threshold derived from the daily *SAIDI* data;	See our response to 17.1 above. We are not proposing to apply the STPIS.

17.1(e)	The incentive rates to apply to each supply reliability area.	See our response to 17.1 above. We are not proposing to apply the STPIS.
17.1	Note: All calculations must be made in accordance with the *STPIS* and using data which complies with the *STPIS* definitions.	See our response to 17.1 above. We are not proposing to apply the STPIS.
17.2	If *PWC* proposes adjustments to the *STPIS* targets away from those based upon raw historical data *PWC* must provide, in respect of each adjustment:	
17.2(a)	the reasons for the adjustment;	We have not departed from the AER's decision in the Framework and Approach paper to not apply a STPIS for the forthcoming period. Our proposed application of incentives schemes including STPIS is discussed in Section 15 of Power and Water's regulatory proposal document.
17.2(b)	the quantum of the adjustment, and the effect of the adjustment on the targets for each of the supply reliability areas; and	See our response to 17.2(a) above. We are not departing from the AER's decisions not to apply the STPIS in the forthcoming period.
17.2(c)	the method, basis and empirical data used as justification for the adjustment.	See our response to 17.2(a) above. We are not departing from the AER's decisions not to apply the STPIS in the forthcoming period.
18	**PROPOSED CONTINGENT PROJECTS**	
18.1	For each contingent *project* proposed in the *regulatory proposal*, provide:	We have not proposed any contingent projects in our forecast capex. None of our forecast capex meets the criteria or threshold for a contingent project.
18.1(a)	a description of the *proposed contingent project*, including reasons why *PWC* considers the *project* should be accepted as a *contingent project* for the *forthcoming regulatory control period*;	See our response to 18.1 above. We are not proposing any contingent projects.
18.1(b)	the *proposed contingent capex* which *PWC* considers is reasonably required for the purpose of undertaking the *proposed contingent project*;	See our response to 18.1 above. We are not proposing any contingent projects.

18.1(c)	the methodology used for developing that forecast and the key assumptions that underlie it;	See our response to 18.1 above. We are not proposing any contingent projects.
18.1(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*;	See our response to 18.1 above. We are not proposing any contingent projects.
18.1(e)	a demonstration that the proposed contingent *capex* for each *proposed contingent project*:	See our response to 18.1 above. We are not proposing any contingent projects.
18.1(e)(i)	is not included (either in part of in whole) in *PWC's* proposed total *forecast capex* for the *forthcoming regulatory control period*;	See our response to 18.1 above. We are not proposing any contingent projects.
18.1(e)(ii)	reasonably reflects the *capex* criteria, taking into account the *capex* factors, in the context of the *proposed contingent project*; and	See our response to 18.1 above. We are not proposing any contingent projects.
18.1(e)(iii)	exceeds either $30 million ($nominal) or 5 per cent of *PWC's* proposed annual revenue requirement for the first year of the *forthcoming regulatory control period*, whichever is larger amount.	See our response to 18.1 above. We are not proposing any contingent projects.
18.1(f)	the proposed trigger events relating to the *proposed contingent project*.	See our response to 18.1 above. We are not proposing any contingent projects.
18.2	For each proposed *trigger event relating* to the *proposed contingent project* referred to in paragraph 18.1(f), demonstrate:	See our response to 18.1 above. We are not proposing any contingent projects.

18.2(a)	the proposed *trigger event* is reasonably specific and capable of objective verification;	See our response to 18.1 above. We are not proposing any contingent projects.
18.2(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;	See our response to 18.1 above. We are not proposing any contingent projects.
18.2(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 *distribution network* as a whole;	See our response to 18.1 above. We are not proposing any contingent projects.
18.2(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*;	See our response to 18.1 above. We are not proposing any contingent projects.
18.2(e)	the proposed *trigger event* is a condition or event, the occurrence of which is probable during the *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:	See our response to 18.1 above. We are not proposing any contingent projects.
18.2(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	See our response to 18.1 above. We are not proposing any contingent projects.
18.2(e)(ii)	the costs associated with the event or condition are not sufficiently certain.	See our response to 18.1 above. We are not proposing any contingent projects.

18.3	Provide a summary of *PWC*'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*.	See our response to 18.1 above. We are not proposing any contingent projects.
19	**REVENUES FOR STANDARD CONTROL SERVICES**	
19.1	Provide *PWC'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 *PWC's regulatory proposal*.	We provide our calculation of forecast unsmoothed and smoothed revenue for SCS in "SCS post-tax revenue model" (Attachment 12.1).
19.2	Provide details of any departure from the *AER's post-tax revenue model* for the calculations referred to in paragraph 19.1 and the reasons for that departure.	We have departed from the AER's post-tax revenue model by using the year-on-year tracking method to forecast depreciation of existing assets. We explain this further in Section 12 of our regulatory proposal, and note that this method has been adopted by the AER in recent decisions, including those for the Victorian DNSPs in May 2016. We rely on the same reasons to support this departure as were accepted by the AER in those decisions.
20	**INDICATIVE IMPACT ON ANNUAL ELECTRICITY BILLS**	
20.1	For the purposes of calculating the impact of *PWC's regulatory proposal* on the annual electricity bill of typical residential and business *customers* in the Northern Territory, 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.	We confirm that we completed Template 7.6 in "Category Analysis RIN Workbooks – Consolidated" (Attachment 11.5). The data source for the information is contained in the model "Reset RIN Population Model" (Attachment 11.16)

21	PROPOSED TARIFF STRUCTURE STATEMENT	
21.1	Provide the model(s) used to calculate the *long run marginal cost* estimates in *PWC'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*.	We have provided the "SCS Pricing model" (Attachment 12.3) which provides the long run marginal cost estimates underlying Power and Water's proposed Tariff Structure Statement (TSS) provided in Attachment 2.1.
21.2	Provide and describe the methodology and assumptions used to prepare the *long run marginal cost* estimates in paragraph 21.1.	We have identified our long run marginal cost estimates and described our methodology for these estimates in section 6 of the document "Tariff Structure Statement" (Attachment 2.1).
21.3	Describe the relationship between the expenditure, demand and other inputs (as appropriate) used in the model provided under paragraph 21.1 and the expenditure, demand and other forecasts (as appropriate) provided as part of the building block proposal for the *forthcoming regulatory control period*.	Our pricing model assumptions are consistent with the inputs in the regulatory proposal.
22	**REGULATORY ASSET BASE AND TAX REPORTING**	
22	**REGULATORY ASSET BASE**	
22.1	Provide *PWC'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.*	We provide our calculation of the Regulatory Asset Base for SCS in each year of the regulatory period in "SCS and ACS metering roll-forward model" (Attachment 12.11).

22.2	Provide details of each departure from the underlying methods in the *AER's roll forward model* for the calculation referred to in paragraph 22.1 and the reasons for that departure.	We have not proposed any departures from the underlying methods in the AER's roll forward model. We explain our application of those methods further in Section 12 of our Regulatory Proposal document and "Establishing the opening RAB" (Attachment 1.11).
22.3	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 propose adjusting our asset base at the start of the 2019-24 regulatory period for changes to service classification. Specifically, ACS metering was classified as SCS over the current period. We propose to treat the two services differently over the 2019-24 regulatory period. To give effect to this we split the closing regulatory asset base as at 30 June 2019 in to an SCS asset base and an ACS metering asset base. This was relatively uncomplicated because the asset classes used to roll forward the RAB over the current regulatory period could be directly assigned to either SCS or ACS metering. We explain how we roll-forward the regulatory asset base further in Section 12 of our Regulatory Proposal document and "Establishing the opening RAB" (Attachment 1.11). The actual values are shown in "SCS and ACS metering roll-forward model" (Attachment 12.11).
22.4	Provide details of actual *capex*, *asset* disposal (based on sale proceeds) and customer contribution values across *asset* classes in the *roll forward model* for 2013-14 and for each *regulatory year* of the *current regulatory control period*. Values in the roll forward model need to be consistent with those reported in *Workbook 3 – category analysis*, *regulatory template* 8.2. The asset classes must be consistent with those approved in the previous determination for the 2014-19 regulatory control period.	We provide this in template 8.2 of the category analysis template using the Utilities Commission's asset classes, and in "SCS and ACS metering roll-forward model" (Attachment 12.11) using our proposed asset classes. Our reasons for adopting different asset classes to those used by the Utilities Commission is explained in "Establishing the opening RAB" (Attachment 1.11).
23	**DEPRECIATION SCHEDULES**	

23.1	Provide *PWC's* calculation of the depreciation amounts for the relevant *distribution system* in respect of *standard control services* for each *regulatory year* of:	
23.1(a)	the *current regulatory control period* using the *AER's roll forward model*, which is to be submitted as part of the *regulatory proposal*	The calculations of depreciation amounts for the current regulatory period is provided in "SCS and ACS metering roll-forward model" (Attachment 12.11).
23.1(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*.	The calculations of depreciation amounts for the forthcoming regulatory period is provided in "SCS Post-tax Revenue Model" (Attachment 12.1).
23.2	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 23.1 and the reasons for that departure.	As noted in response to 22.2, we do not propose any departure to the underlying methods in the roll-forward to the extent that they apply to the roll-forward of the regulatory asset base. As noted in response to 19.2, we have departed from the AER's post-tax revenue model by using the year-on-year tracking method to forecast depreciation of existing assets. We explain this further in section 12 of our Regulatory Proposal document. We note this method has been adopted by the AER in recent decisions, including those for the Victorian DNSPs in May 2016. We rely on the same reasons to support this departure as were accepted by the AER in those decisions.
23.3	Identify any changes to standard *asset* lives for existing *asset* classes from the previous *determination*. Explain the reason(s) for each change and provide relevant supporting information.	These are identified and explained in "Establishing the opening RAB" (Attachment 1.11) and supported by "Opening RAB" (Attachment 12.13) and "Updated UC Roll Forward Model" (Attachment 12.14).
23.4	Identify any changes to new *asset* classes from the previous *determination*. Explain the reason(s) for using these new *asset* classes and provide relevant supporting information on their proposed standard *asset* lives.	These are identified and explained in Establishing the opening RAB" (Attachment 1.11).

23.5	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 relevant supporting information. This should include a demonstration of the materiality of the change on the forecast depreciation allowance and the mapping of the residual values to other asset classes from the existing asset classes.	These are identified and explained in "Establishing the opening RAB" (Attachment 1.11) and supported by "Opening RAB" (Attachment 12.13) and "Updated UC Roll Forward Model" (Attachment 12.14).
23.6	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*.	As noted in response to 19.2 and 23.2, we propose adopting the year on year tracking method to depreciate existing assets as at 1 July 2019, which differs from the approach in our proposed roll forward model. We explain this further Section 12 of our Regulatory Proposal document.
24	**CORPORATE TAX ALLOWANCE**	
24.1	Provide *PWC'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*.	Corporate income tax for SCS is provided in "SCS post-tax revenue model" (Attachment 12.1) and for ACS metering is provided in "ACS metering post-tax revenue model" (Attachment 12.2). Our calculations are explained in Section 14 of our Regulatory proposal.
24.2	Provide any tax losses carried forward to 1 July 2019. Include relevant details about how this amount has been calculated.	We assume no tax losses. We have not identified any reason why tax losses should be positive.
24.3	Provide details of each departure from the *AER's post-tax revenue model* for the calculations referred to in paragraph 24.1 and the reasons for that departure.	We are proposing no departures to how the cost of corporate income tax is calculated in the AER's post-tax revenue model.

24.4	Provide the standard tax *asset* lives for each of the *asset* classes in the *AER's post-tax revenue model*, which is to be submitted as part of *PWC's regulatory proposal*. Include relevant supporting information on the proposed standard tax *asset* lives, including Federal tax laws governing depreciation for tax purposes.	We provide our standard tax asset lives for SCS in "SCS post-tax revenue model" (Attachment 12.1) and for ACS metering in "ACS metering post-tax revenue model" (Attachment 12.2). These lives are explained in "Establishing the opening TAB" (Attachment 1.11), and supported by "Hayne & Co PTY Limited -Tax Life Validation Letter" (Attachment 1.13) and "Opening TAB" (Attachment 12.12)
24.5	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.	We have interpreted this question as asking for any differences between how we have treated expenditure in our proposed regulatory asset base and tax asset base. Adopting this interpretation, the only difference is in the treatment of capital contributions – which are removed from the regulatory asset base, but not the tax asset base. This difference in treatment is reflected in the AER's post-tax revenue model and the AER's roll-forward model.
25	**SETTING THE TAX ASSET BASE**	
25.1	In accordance with the following clauses and *Workbook 3 – category analysis, regulatory template* 9.1:	We have completed template 9.1 in accordance with the AER's instructions as can be demonstrated in "Category Analysis RIN Workbooks – Consolidated" (Attachment 11.5). We have populated this table using "CA RIN TAB Allocation Method" (Attachment 11.15).
25.1(a)	provide the tax asset values based on tax asset values assessed by the Australian Taxation Office (where available) from 2002-03 or justifiable starting point to 2018-19. Provide estimated values based on *PWC's* records where actual values from the Australian Taxation Office are not available (e.g. 2017-18 and 2018-19).	Our calculations are included at "CA RIN TAB Allocation Method" (Attachment 11.15). This is supported by "Hayne & Co PTY Limited -Tax Life Validation Letter" (Attachment 1.13), "SCS and ACS metering roll forward model" (Attachment 12.11), "Opening TAB" (Attachment 12.12), and explained in "Establishing the opening TAB" (Attachment 1.12).

25.1(b)	From 2002-03 (or *PWC's* proposed starting point to 2018–19), in accordance with *Workbook 3 – category analysis*, *regulatory template* 9.1, tables 9.1.1.1, 9.1.1.2, and 9.1.2 provide the relevant information requested therein in accordance with *PWC's* tax asset classes.	Our calculations are included at "CA RIN TAB Allocation Method" (Attachment 11.15). This is supported by "Hayne & Co PTY Limited -Tax Life Validation Letter" (Attachment 1.13), "SCS and ACS metering roll forward model" (Attachment 12.11), "Opening TAB" (Attachment 12.12), and explained in "Establishing the opening TAB" (Attachment 1.12).
25.1(c)	the tax asset classes used for establishing the opening tax asset base as at 1 July 2019 are to be based on the same *asset* classes as approved for the RAB for the 2014–19 regulatory control period. If *PWC* proposes different *asset* classes in the PTRM for the *forthcoming regulatory control period*, provide the reallocation of the opening tax asset base as at 1 July 2019 across the proposed *asset* classes in the PTRM. This should include a demonstration of the mapping of the opening tax asset base values at 1 July 2019 to different *asset* classes from the existing *asset* classes.	We have populated template 9.1 using the same asset classes as were approved by the Northern Territory Utilities Commission for the RAB for the 2014-19 regulatory period. However, we propose using different asset classes in our regulatory proposal, as explained in "Establishing the opening RAB" (Attachment 1.11) and "Establishing the opening TAB (Attachment 1.12). To ensure that the closing TAB as at 30 June 2019 in template 9.1 matched that which we input to our proposed SCS and ACS metering PTRMs, we have had to allocate the tax depreciation that we calculated for the 2014-19 period using our proposed roll-forward model (see Attachment 12.11) across the Utilities Commission asset classes. This was undertaken in "CA RIN | TAB allocation model" (Attachment 11.15).

25.2	Provide all information *PWC* relied on to complete, and relies on to substantiate the data, provided in *regulatory template* 9.1 This information includes any consultant report, Australian Taxation Office tax assessments and audit report or report from an independent auditor of the findings of an agreed-upon procedures engagement (the report and any separate report developed for management in respect of the engagement should be provided as an attachment to *PWC's regulatory proposal*).	The information that we relied upon is included in "Establishing the opening TAB)" (Attachment 1.12), "Hayne & Co PTY Limited -Tax Life Validation Letter" (Attachment 1.13), "SCS and ACS metering roll forward model" (Attachment 12.11), "Opening TAB" (Attachment 12.12), and explained in "Establishing the opening TAB" (Attachment 1.12), and "CA RIN | TAB allocation model" (Attachment 11.15).
25.3	Provide the origin and source of information provided in respect of paragraph 25.2.	This is explained in "Establishing the opening TAB" (Attachment 1.12).
25.4	Explain:	
25.4(a)	how the opening tax *asset* values for the chosen starting point have been determined;	This is explained in "Establishing the opening TAB" (Attachment 1.12).
25.4(b)	how assets have been segregated to separately identify whether they are Regulatory Asset Base or non-Regulatory Asset Base assets;	This is explained in "Establishing the opening TAB" (Attachment 1.12).
25.4(c)	how standard control *assets* have been segregated into *asset* classes, including identification of the *asset* classes;	This is explained in "Establishing the opening TAB" (Attachment 1.12).
25.4(d)	how depreciation has been calculated for each of the *asset* classes identified, including the following:	This is explained in "Establishing the opening TAB" (Attachment 1.12).

25.4(d)(i)	depreciation method (that is, whether based on prime cost or diminishing value); and	This is explained in "Establishing the opening TAB" (Attachment 1.12).
25.4(d)(ii)	tax depreciation profile (including the tax life used and justification as to why the tax life adopted is appropriate).	This is explained in "Establishing the opening TAB" (Attachment 1.12).
25.4(e)	how expenditure and depreciation on work-in-progress is accounted for, including when it is recognised (that is, on an as incurred or at year end basis);	This is explained in "Establishing the opening TAB" (Attachment 1.12).
25.4(f)	how tax losses are taken into account and whether losses are carried forward to the closing tax *asset* values;	This is explained in "Establishing the opening TAB" (Attachment 1.12).
25.4(g)	where disposals have occurred, how the value of disposals are determined (that is, whether based on net book value or sale proceeds).	This is explained in "Establishing the opening TAB" (Attachment 1.12).
26	**MISCELLANEOUS REPORTING**	
26	**RELATED PARTY TRANSACTIONS**	
26.1	Identify and describe all entities which:	Power and Water notes that it obtains services such as payroll, fleet and IT under a Northern Territory Government contract with the Department of Corporate and Information Services. Based on our understanding of the AER's definition of related party, we have not identified any related party that contribute to the provision of distribution services.
26.1(a)	are a *related party* to *PWC* and contribute to the provision of *distribution services*; or	See our response to Question 26.1 above – we have not identified any related parties that contribute to distribution services.
26.1(b)	have the capacity to determine the outcome of decisions about *PWC's* financial and operating policies.	See our response to Question 26.1 above – we have not identified any related parties that contribute to distribution services.

26.2	Provide a diagram of the organisational structure depicting the relationships between all the entities identified in the response to paragraph 26.1.	See our response to Question 26.1 above – we have not identified any related parties that contribute to distribution services.
26.3	Identify:	See our response to Question 26.1 above – we have not identified any related parties that contribute to distribution services.
26.3(a)	all arrangements or *contracts* between *PWC* and any of the other entities identified in the response to paragraph 26.1 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	See our response to Question 26.1 above – we have not identified any related parties that contribute to distribution services.
26.3(b)	the service or services that are the subject of each arrangement or *contract*.	See our response to Question 26.1 above – we have not identified any related parties that contribute to distribution services.
26.4	For each service identified in the response to paragraph 26.3(b):	See our response to Question 26.1 above – we have not identified any related parties that contribute to distribution services.
26.4(a)	provide:	See our response to Question 26.1 above – we have not identified any related parties that contribute to distribution services.
26.4(a)(i)	a description of the process used to procure the service; and	See our response to Question 26.1 above – we have not identified any related parties that contribute to distribution services.
26.4(a)(ii)	supporting documentation including, but not limited to, requests for tender, tender submissions, internal committee papers evaluating the tenders, *contracts* between *PWC* and the relevant provider.	See our response to Question 26.1 above – we have not identified any related parties that contribute to distribution services.
26.4(b)	explain:	See our response to Question 26.1 above – we have not identified any related parties that contribute to distribution services.

26.4(b)(i)	why that service is the subject of an arrangement or *contract* (i.e. why it is outsourced) instead of being undertaken by *PWC* itself;	See our response to Question 26.1 above – we have not identified any related parties that contribute to distribution services.
26.4(b)(ii)	whether the services procured were provided under a standalone *contract* or provided as part of a broader operational agreement (or similar);	See our response to Question 26.1 above – we have not identified any related parties that contribute to distribution services.
26.4(b)(iii)	whether the services were procured on a genuinely competitive basis and if not, why; and	See our response to Question 26.1 above – we have not identified any related parties that contribute to distribution services.
26.4(b)(iv)	whether the service (or any component thereof) was further outsourced to another provider.	See our response to Question 26.1 above – we have not identified any related parties that contribute to distribution services.
27	**VEGETATION MANAGEMENT COMPLIANCE**	
27.1	Provide compliance *audits* of *vegetation management* work conducted by *PWC* during the *current regulatory control period*.	Power and Water does not complete formal audits of vegetation work. Our contract managers continually monitor the activities of contractors but no documented audit is undertaken.
28	**CORPORATE STRUCTURE**	
28.1	Provide charts that set out:	
28.1(a)	the group corporate structure of which *PWC* is a part; and	Please refer to section 4 of "Cost Allocation Method" for a chart of the corporate group structure of which Power Networks is a part. We have previously submitted this document to the AER for approval.
28.1(b)	the organisational structure of *PWC*.	Please refer to section 4 of "Cost Allocation Method" for a chart of the organisational structure of which Power Networks is a part. We have previously submitted this document to the AER for approval.
29	**FORECAST MAP OF DISTRIBUTION SYSTEM**	

29.1	Provide a forecast map of *PWC*'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*.	This is provided at Appendix 2 to this document, and shows the location of Wishart zone substation (near Darwin), which is the only new major network asset that we have proposed to be constructed in the forthcoming regulatory period.
30	**TRANSITIONAL ISSUES**	
30.1	Provide information on transitional issues (expressly identified in the *NER* or otherwise), which PWC 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:	
30.1(a)	the transitional issue;	Please refer to Section 4 of the Regulatory Proposal document ("Regulatory baseline") for a full discussion on the transitional changes impacting Power and Water. In the chapter, we identify a transitional issue related to extensive changes in the legislative and regulatory framework under which we operate. More detailed information is provided in the document "Regulatory Baseline" (Attachment 1.3).
30.1(b)	what has caused the transitional issue;	Please see our response to 30.1(a) above for references to where we have addressed transitional issues in our regulatory proposal, including the cause of the transitional issue.
30.1(c)	how the transitional issue impacts on *PWC*; and	Please see our response to 30.1(a) above for references to where we have addressed transitional issues in our regulatory proposal, including the impact of the transitional issue.
30.1(d)	how *PWC* considers the transitional issue could be addressed.	Please see our response to 30.1(a) above for references to where we have addressed transitional issues in our regulatory proposal, including how we propose to address the transitional issue.
31	**ASSURANCE REQUIREMENTS**	
31	**AUDIT AND REVIEW REPORTS**	

31.1	Provide the *audit report* and *review reports* as applicable, prepared in accordance with the requirements set out in Appendix C.	We have provided the audit report and review reports as required as part of our 16 March 2018 submission to the AER.
31.2	Provide all reports from the *auditor* to *PWC*'s management regarding the *audit* review and/or *auditors*' opinions or assessment.	We have provided the audit report and review reports as required as part of our 16 March 2018 submission to the AER.
32	**OTHER INFORMATION**	
32	**CONFIDENTIAL INFORMATION**	
32.1	This clause applies to any information *PWC* provides:	
32.1(a)	in response to Schedule 1;	
32.1(b)	in a *regulatory proposal*, revenue proposal, proposed negotiating framework, proposed pricing methodology, proposed tariff structure statement, access arrangement proposal or access arrangement for the *forthcoming regulatory control period* (a Proposal)	
32.1(c)	in a revision or amendment to a Proposal; and	
32.1(d)	in a submission *PWC* makes regarding a Proposal or a revised or amended Proposal; (together, *PWC's* Information).	

32.2	If *PWC* wishes to make a claim for confidentiality over any of *PWC's* Information, provide the details of that claim in accordance with the requirements of the *AER's Confidentiality Guideline*, as if it extended and applied to that claim for confidentiality.	Please refer to Power and Water's "Confidentiality template" (Attachment 1.14)
32.3	Provide any details of a claim for confidentiality in response to paragraph 32.2 at the same time as making the claim for confidentiality.	Please refer to Power and Water's "Confidentiality template" (Attachment 1.14)
33	**33. COMPLIANCE WITH SECTION 71YA OF THE NEL**	
33.1	Provide a statement attesting that:	
33.1(a)	Where any expenditure or cost is has been incurred or is forecast to be incurred by *PWC,* as a result of or incidental to a review under Division 3A – *Merits review and other non-judicial review* – of the *NEL*:	We can confirm that we have not applied for a review under Division 3A – *Merits review and other non-judicial review* – of the *NEL*, and therefore there are no expenditure or costs incurred or forecast in our regulatory proposal.
33.1(a)(i)	*PWC* has not included any of that expenditure or cost, or any part of that expenditure or cost, in its forecast capital or operating expenditures for a network revenue or pricing determination; and	We can confirm that we have not applied for a review under Division 3A – *Merits review and other non-judicial review* – of the *NEL*, and therefore there are no expenditure or costs incurred or forecast in our regulatory proposal.
33.1(a)(ii)	PWC has not recovered any of that expenditure or cost, or any part of that expenditure or cost, from end users; and	We can confirm that we have not applied for a review under Division 3A – *Merits review and other non-judicial review* – of the *NEL*, and therefore there are no expenditure or costs incurred or forecast in our regulatory proposal.
33.1(a)(iii)	*PWC* has not sought to pass through any of that expenditure or cost, or any part of that expenditure or cost, to end users; or	We can confirm that we have not applied for a review under Division 3A – *Merits review and other non-judicial review* – of the *NEL*, and therefore there are no expenditure or costs incurred or forecast in our regulatory proposal.

33.1(b)	Where no expenditure or cost has been incurred or is forecast to be incurred by *PWC,* as a result of or incidental to a review under Division 3A – *Merits review and other non-judicial review* – of the *NEL*:	We can confirm that we have not applied for a review under Division 3A – *Merits review and other non-judicial review* – of the *NEL*, and therefore there are no expenditure or costs incurred or forecast in our regulatory proposal.
33.1(b)(i)	No such expenditure or cost has been incurred or is forecast to be incurred.	We can confirm that we have not applied for a review under Division 3A – *Merits review and other non-judicial review* – of the *NEL*, and therefore there are no expenditure or costs incurred or forecast in our regulatory proposal.
34	**34. IDENTIFICATION OF CERTAIN COSTS IN ACTUAL CAPITAL AND OPERATING EXPENDITURE**	
34.1	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 *PWC* has incurred as a result of, or incidental to, a review under Division 3A – *Merits review and other non-judicial review* – of the *NEL*.	We can confirm that we have not applied for a review under Division 3A – *Merits review and other non-judicial review* – of the *NEL*, and therefore there are no expenditure or costs incurred or forecast in our regulatory proposal.

Appendix 1 – Material assumptions

We have identified key assumptions underlying our capex and opex forecasts for standard control services in Chapters 10 and 11 of our regulatory proposal respectively, consistent with the information requirements in the NER. In responding to questions 1.4(b) and 1.5 of Schedule 1 of the RIN, we have interpreted key assumptions as "material".

In Table A.1 below we provide responses to the AER's RIN

- The issue and assumption (1.4b)
- Source or basis of assumption (1.5a)
- If applicable, the assumption's quantum; (1.5b)
- Whether and how the assumption has been applied and was taken into account 1.5(c)
- The effect or impact of the assumption on the capital and operating expenditure forecasts in the forthcoming regulatory control period taking into account:
  - The actual expenditure incurred during the current regulatory control period (1.5d(i))
  - The sensitivity of the forecast expenditure to the assumption. (1.5d(ii))

For clarity we have not been able to identify the impact of the assumption relative to actual expenditure incurred in the current period, and have therefore not addressed this in the table.

Table A.1 – Material Assumptions

Issue	Assumption	Source/ Basis	Quantum	Application	Impact sensitivity
1. Company structure and ownership arrangements	Our forecasts reflect Power and Water's current company structure and ownership arrangements.	Our structure and ownership arrangements are set out in the "Cost Allocation Method" previously submitted to the AER	Not able to be quantified because depends on organisational structure and its implications on allocation of shared costs	Capex and Opex	Not able to be estimated
2. Regulatory obligations and requirements	Our forecasts are based on legislative and regulatory instruments applicable to Power and Water and as in force on 1 July 2017.	Please see document "Regulatory baseline" (Attachment 1.3)	Unable to be quantified - depends on the degree of further legislative and regulatory change to be implemented by the NT Government as part of reform program	Capex and Opex	Not able to be estimated
3. Security of supply and network reliability	Our forecasts will maintain, but will not improve, system-wide security of supply and network reliability, consistent with clause 6.5.7 of the NER.	Please see "Network Technical Code and Planning Criteria" (Attachment 4.2)	Not able to be quantified as there is no counterfactual and no change being contemplated.	Capex	Not able to be estimated
4. Service classification	Our forecasts reflect the service classification in the AER's F&A paper.	AER's F&A which we have accepted in full	Not able to be quantified because would depend on which services would move between classifications.	Capex and Opex	Not able to be estimated

Issue	Assumption	Source/ Basis	Quantum	Application	Impact sensitivity
5. Maximum demand, customer and connection growth	Our forecasts are required to meet the maximum demand, customer and connection growth forecasts prepared by AEMO. As the independent market operator, AEMO's forecasts are reasonable and credible.	Please refer to the document "AEMO - Power and Water Corporation Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017" (Attachment 4.4)	We have not prepared any forecasts other than on the basis of AEMO's forecasts. For this reason, we are not in a position to identify an alternative.	Capex and Opex	Not able to be estimated
6. Connections policy	Our forecasts reflect Power and Water's proposed new connections policy that complies with Chapter 5A of the NT NER.	Please refer to "Proposed connection policy" (Attachment 7.2).	If the proposed connection policy did not require capital contributions from customers, our proposed SCS net capex would be approximately $60 million higher (FY 19 real)	Capex	Between 0 and +$60 million of SCS net capex (real, FY 19)
7. Cost allocation and capitalisation	Our forecasts reflect the cost allocation method that has been submitted to the AER, which includes our approach to capitalisation.	Please refer to CAM that has been previously provided to the AER.	We have not prepared any forecasts other than on the basis of our proposed CAM. For this reason, we are not in a position to identify an alternative.	Capex and Opex	Not able to be estimated

Issue	Assumption	Source/ Basis	Quantum	Application	Impact sensitivity
8. Unit rates	The unit rates that Power and Water has applied in developing its capex forecasts are representative of the costs that will be incurred in the next period.	Please refer to "Capex overview document" (Attachment 4.1) for a description of unit rates.	We have not prepared any forecasts other than on the basis of our proposed CAM. For this reason, we are not in a position to identify an alternative.	Capex	Not able to be estimated
9. Cost escalations	The cost escalations that Power and Water has applied in developing its forecasts are representative of the increased costs that we will incur in the next period.	Please refer to section 11.7 of the regulatory proposal document for description on basis of cost escalation for opex. We have applied the same escalations for capex.	Please refer to section 11.10 of the regulatory proposal document.	Capex and Opex	We have not undertaken sensitivity analysis due to the difficulty in quantifying a reasonable maximum and minimum.
10. Inflation	The inflation that Power and Water has applied in developing its forecasts is representative of the inflation-related costs that will be incurred in the next period and is consistent with the AER-preferred inflation forecasting method.	Please refer to Section 13.4 of the regulatory proposal document.	Difficult to provide a counter-factual estimate	Capex and Opex	We have not undertaken sensitivity analysis due to the difficulty in quantifying a reasonable maximum and minimum.
11. Current period capex program	Our capex forecasts for 2019-20 to 2023-24 assume that we will deliver our forecast capex program for 2017-18 and 2018-19.	Please refer to section 3 of the "Capex Overview Document" (Attachment 4.1) for a discussion on our current period capex program.	Difficult to quantify.	Capex	We have not undertaken sensitivity analysis, as counter-factual scenarios are difficult to reasonably estimate.

Issue	Assumption	Source/ Basis	Quantum	Application	Impact sensitivity
12. Efficient opex base year	Our adjusted (including for efficiencies) 2016-17 opex provides a reasonable basis for our opex forecasts and is representative of our requirements to sustainably provide our services.	Please refer to the document "Opex Base Year Justification"(Attachment 3.1)	Please refer to the document "Opex Base Year Justification"	Opex	We have not undertaken sensitivity analysis.

Appendix 2 – Map of distribution network

This appendix provides a forecast map of the distribution network including the location of new major assets as required by question 29 of Schedule 1 of the AER's RIN. The only new major asset we will be installing on the network is Wishart Zone substation in Darwin. Please see section 3.2 of Power and Water's regulatory proposal document for more information on our network.