Nuttall Consulting

*Regulation and business strategy*

# Report – Principle Technical Advisor

## Aurora Electricity Distribution Revenue Review

## Revised Proposal

A report to the AER

Final Report

19 April 2012

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# Executive Summary

## *Introduction*

The Australian Energy Regulator (AER), in accordance with its responsibilities under the National Electricity Rules (NER), is to make a determination in 2012 associated with Aurora Energy Pty Ltd (Aurora), the Tasmanian Distribution Network Service Provider (DNSP). Nuttall Consulting has been engaged by the AER to provide technical advice to aid in this process.

The AER assessed the Aurora original proposal and in November 2011 released the draft determination for Aurora. To inform the draft determination, Nuttall Consulting provided reports to the AER detailing technical advice on a number of matters associated with Aurora's original proposal.

In January 2012, Aurora released its revised regulatory proposal. In this revised proposal, Aurora identifies that it has not accepted all of the AER's draft determination and has made other alterations based upon revised information and assumptions. Consequently, the revised proposal sets out alternate revenue requirements for the next regulatory period.

The AER has requested that Nuttall Consulting provide advice on a number of technical matters associated with the revised proposal. To assess these matters, we have reviewed the additional information provided by Aurora in its revised proposal. Where necessary, we have reconsidered the information provided by Aurora in support of its original proposal and requested additional information from Aurora.

The main matters under review cover:

- Standard control capex - a number of positions in our original review of Aurora's capital expenditure that have been challenged by Aurora in its revised proposal
- Standard control opex - opex step-changes associated an IT project.

The AER has also requested that we provide advice on a number of specific technical matters associated with other aspects of the revised proposal, including alternative control services. These matters are not covered in this executive summary; however, more detail on each matter is included in the main body of this report.

## *Standard control capex*

Our review of Aurora's original proposal included an extensive review of Aurora's capex forecast. Our approach included both high-level analysis and a detailed review of specific planned projects and programs. The broad findings of this review were that Aurora's capex forecast should be rejected. We advised a substitute forecast that was based upon the findings of our detailed review. These findings were used by the AER in its draft determination.

Aurora's revised proposal has allowed for some of these findings. However, in a number of cases, Aurora has challenged these findings. The AER has requested that we advise on a number of the matters raised in Aurora's revised proposal. These matters can be considered in terms of two main capex categories: reinforcement capex and non-demand driven capex.

***Reinforcement capex***

Our substitute allowance for reinforcement capex was based upon a detailed review of a sample of the planned projects and programs that underpinned Aurora's capex.

Aurora's revised proposal has challenged our findings on two of the projects we reviewed. It has also changed the circumstances surrounding a number of other projects that were not part of our sample.

The AER has requested that Nuttall Consulting reviews the technical matters raised by Aurora on these projects. It has also requested that we re-assess our findings across the sample of projects, in light of the maximum demand forecast that underpins Aurora's revised proposal[1].

We have reviewed the additional information provided by Aurora. This has led to some modest changes to our previous findings on the two projects included in our sample review. With regard to one project (Sandford), the change is mainly the result of a revised project scope proposed by Aurora that significantly reduces the cost of the project (from $6.5 million to $1.5 million). With regard to the other project (Geilston Bay), the change in our position is mainly the result of an error in Aurora's original proposal on the project timing and the revised load forecast.

With regard to the other projects, we have provided commentary on our views on various technical matters raised. For one project (Gretna), we do not consider that the revised information supports the need for this project. For the others, we accept there may be a need, but in our view the methodology used to derive the substitute capex should allow for these projects. Therefore, how the AER uses this advice depends on its approach to derive the substitute allowance from the sample group findings.

Our re-assessment of the sample projects, due to the revised load forecast, has resulted in some changes to a few projects – some up and others down. We have not re-calculated the substitute allowance based upon these changes – we consider this should be performed by the AER. Nonetheless, we do not anticipate that the overall change to the capex will be very significant.

***Non-demand driven capex***

Our substitute allowance for non-demand driven capex was based upon a detailed review of the majority of programs that underpinned Aurora's capex.

Aurora's revised proposal has challenged our findings associated with replacement programs in five asset categories: poles, underground cables, distribution transformers, distribution switchgear and zone substation transformers. Aurora has also criticised our use of the repex model in assessing the replacement forecast.

Aurora's revised proposal has also challenged our findings associated with many of the programs that we considered were associated with reliability and efficiency improvements.

[1] Aurora has also challenged the overall methodology applied to determine a substitute allowance from the findings of the sampled projects. The AER has not requested us to advise on this matter.

The AER has requested that Nuttall Consulting reviews the technical matters raised by Aurora on these issues.

With regard to the replacement programs, we have reviewed the revised information provided by Aurora. To a large extent, we do not agree that this supports the increases proposed by Aurora. We have however accepted that some modest increases are justified. This is most notable with regard to:

- the distribution and zone substations, where we have allowed for a modest increase to purchase some additional spares to manage risks associated with the fleet
- the underground cables, where we have accepted that additional information provided by Aurora on historical cable failures supports a modest increase from our original position.

With regard to the challenges to our use of the repex model, we consider that whether these are valid or not should not affect the substitute allowance as this was based upon specific adjustments resulting from our detailed review of the replacement programs. Nevertheless, we have considered the specific matters raised and do not consider that they are valid. The matters largely revolve around the validity of the repex model findings. However, we consider that it is not appropriate to consider the validity of the repex model in isolation. It must be viewed in the broader context of the overall review and various approaches we have applied that support each other.

Finally, with regard to the programs we considered would be justified by their reliability (or efficiency) improvements, we have reviewed the information provided by Aurora and still maintain that this should be the case. We have not found clear mandatory obligations that require Aurora to undertake these programs. Furthermore, we still believe that reductions in base-line opex and improvements in reliability would be the main factors justifying these programs. We have however accepted that one program (the fuse reach program) may be justified purely on safety grounds.

## *Standard control opex*

The AER has requested that we advise on an opex step change associated with a proposed IT project. Aurora has proposed a step change in operating expenditure of $12 million associated with this project. Aurora has identified that the increased opex is due to the move to a new-generation platform for its information system.

We have reviewed the information Aurora has provided to support this project. In our view, a step increase in opex is reasonable. However, the information provided does not support the need for such a large step increase. Based upon our review, we consider that the Aurora opex step change for this project should be reduced by approximately 63%.

The majority of this reduction is based on the removal of items that we do not believe represent real or likely future expenditures. These reductions are consistent with Aurora's own internal documentation.

Other minor reductions are based on the removal or replacement of existing license fees and expenditures included in Aurora's cost estimate, and other expenditure items that we consider there is no regulatory obligation to maintain.

# 1 Introduction

The Australian Energy Regulator (AER), in accordance with its responsibilities under the National Electricity Rules (NER), is to make a determination in 2012 associated with Aurora Energy Pty Ltd (Aurora), the Tasmanian Distribution Network Service Provider (DNSP).

As part of this process, Aurora provided a regulatory proposal (the Aurora original proposal) that, among other things, set out its proposed revenue requirements for the next regulatory period, covering 2012/13 to 2016/17.

The AER assessed the Aurora original proposal and in November 2011 released the Draft Distribution Determination for Aurora.

In January 2012, Aurora released its revised regulatory proposal (the Aurora revised proposal). In this revised proposal, Aurora identifies that it has not accepted all of the recommendations contained in the Draft Distribution Determination and has made other alterations based upon revised information and assumptions. Consequently, the revised proposal sets out alternate revenue requirements for the next regulatory period.

The AER is required to assess regulatory proposals in accordance with the provisions of the NER. Nuttall Consulting has been engaged by the AER to provide technical advice on Aurora's regulatory proposals, and other associated matters.

Two reports to the AER in November 2011 (original reports) set out our reviews associated with the Aurora original proposal[2]. One report dealt largely with our review of capex. The other dealt with our review of some specific categories of the AER's base-line opex.

This document represents the draft report to the AER, based upon our review of issues identified by the AER associated with the Aurora revised proposal.

## 1.1 Terms of reference

The Nuttall Consulting overall terms of reference are maintained from the initial work that was undertaken to review Aurora's original proposal, and summarised in our original report.

For our review of the Aurora revised proposal, the AER has defined a number of specific matters for us to consider. These main matters cover:

- selected projects associated with Aurora's revised reinforcement capex forecast
- selected programs associated with Aurora's non-demand driven capex forecast

[2] Report – Principle Technical Advisor - Aurora Electricity Distribution Revenue Review, dated 11 November 2011, and Report – Principle Technical Advisor - Aurora Electricity Distribution Revenue Review - Operating Expenditure Base-Line, dated 11 November 2011

- a step change in the Aurora's operating expenditure forecast, associated with an IT enhancement project
- selected matters associated with Aurora's alternative control services forecasts.

The AER has also requested that we:

- reconcile our original review findings associated with 2009/10 base-line opex with revised opex forecasts, provided with Aurora's revised proposal
- review the AER's methodology associated with preparing its STPIS SAIDI and SAIFI targets.

This report details our review of these matters.

## 1.2 Methodology

This review is focussed on specific technical items contained in Aurora's revised proposal. The AER has identified a number of specific areas for the Nuttall Consulting review. Our methodology in undertaking this review has included the following:

- a review of Aurora's revised proposal and supporting information
- identification of areas requiring additional information and requests to Aurora for this information
- teleconferences, where necessary, with Aurora relating to the areas of review
- review of additional information provisions
- preparation and drafting of report to the AER of this review.

## 1.3 Structure of report

The report is structured as follows:

- Sections 2 and 3 of this report discuss our review of the matters associated with reinforcement and non-demand driven capex respectively.
- The proposed step change in Information Technology (IT) opex is considered in section 4.
- Section 5 deals with the other matters identified by the AER.
- Section 6 discusses our review of the matters under consideration in alternative control services.

# 2 Reinforcement capex

## 2.1 Overview of original review and Aurora's revised proposal

Nuttall Consulting's original review of capex allocated to the reinforcement category (reinforcement capex) involved:

- high-level comparative analysis of Aurora's reinforcement capex with that of the Victorian DNSPs
- detailed reviews of a sample of Aurora's forecast projects and programs that underpinned its reinforcement capex forecast.

The high-level analysis indicated that Aurora's reinforcement capex, when adjusted for demand growth, was significantly higher than the Victorian DNSPs. Furthermore, based upon the detailed project reviews, we considered that a large portion of the capex for the projects reviewed was not supported by the growth in demand alone. In this regard, we believed that this portion of capex could only be justified by savings in existing levels of opex and/or reliability improvements.

To calculate an adjusted forecast for reinforcement capex, we developed two components associated with the capex of the projects reviewed:

- the proportion we considered could be justified to maintain service levels in light of the forecast demand – the demand component
- the proportion we considered would need to be justified by reductions in opex and/or reliability improvements – the efficiency benefit component.

Given the significant portion of reinforcement capex that the sampled projects represented, we considered it reasonable to apply these proportions to the remaining capex to derive the total reinforcement capex in these two components.

We understand that the AER accepted our findings, and used these to determine its reinforcement capex forecast in its draft decision.

Aurora's revised proposal has challenged our findings on a number of the projects we reviewed, most notably:

- Sandford
- Geilston Bay.

It has also changed the circumstances surrounding a development in Kingston from that which it had assumed in its original proposal. Furthermore, it now considers that it misclassified a project associated with a voltage conversion of the HV network in the Gretna area. It now considers that this should have been classified as non-demand capex, as it is primarily driven by the condition of the existing transformers at the Gretna zone substation.

Aurora has also challenged the methodology we applied, both in terms of developing the efficiency-benefit component and applying both components to the capex associated with projects we did not review. Related to this point, Aurora has also stated that capex associated with the new substation at St Leonards, which was not part of our detailed review, should be fully included in the allowance as it is part of a committed project that has passed the regulatory test.

The AER has requested that Nuttall Consulting reviews the technical matters raised by Aurora in its revised proposal on:

- Sandford
- Geilston Bay.

It has also asked us to consider the revised technical matters associated with:

- Kingston
- Gretna.

The AER has also requested that we review the demand and efficiency components of the projects selected for detailed review, in light of the maximum demand forecast that underpins Aurora's revised proposal.

These four projects are discussed in turn below followed by our revised load forecast assessment.

## 2.2 Revised project reviews

### 2.2.1 Sandford

***Nuttall Consulting original findings***

The original Sandford project involved the development of sub-transmission lines at an approximate cost of $6.5 million, with the majority of capex occurring in 2015/16.

We considered that the need for the proposed project was related to feeder loading and voltage issues in the area – the South Arm peninsula. However, we acknowledged that the project was part of a longer-term strategy to relieve issues in this area and the loading of the existing Rokeby substation.

This longer-term strategy involved the development of the new Sandford substation. This new substation was assumed by Aurora to be deferred to beyond the next period via a non-network solution, of which there was provision for in the opex and capex allowances.

The Sandford network project associated with the next period only involved the development of the sub-transmission lines that would ultimately supply this new substation. In the meantime, these new circuits would operate as a new HV feeder, relieving the existing localised issues in the area.

Our view was that the Aurora information supported the need for the project (in terms of the localised issues and the loading at Rokeby); however, we believed Aurora had not adequately demonstrated that its proposed solution was the most appropriate. Our view was that a much lower cost solution was more likely to be found to be the preferred short-term solution to the localised issues, and noted that further voltage support and/or the use of mobile generation as possible lower cost solutions.

Additionally, we believed that the analysis provided by Aurora that indicated that this non-network project would defer the need for the new Sandford substation, assumed that this non-network solution would also relieve the localised issues[3]. As such, it was not clear to us why any network solution was required if the full non-network solution was allowed for.

Therefore, given we accepted the non-network solution and recommended provision be made for the full amount for this in the opex and capex allowances, we did not consider it was appropriate to also allow for the capex as proposed by Aurora.

The AER's revised load forecast suggested slightly higher demand growth in that area than had been assumed by Aurora in its analysis. Therefore, we considered that 10% of the capex forecast by Aurora was a reasonable allowance to cover the increased risks that may result from that increased demand.

***Aurora revised proposal***

Aurora's revised proposal has accepted our view that its original proposal was too costly, but has not accepted that the non-network solution is sufficient to alleviate all the localised issues[4].

As such, Aurora has proposed an alternative lower-cost network project that it considers would be needed in addition to the allowed non-network solution. This alternative network project essentially involves an alternative overhead route, instead of the far more costly underground and submarine route it had assumed in its original proposal[5].

The capital cost for this revised project is $1.6 million[6], which is much less than the original $6.6 million. However, this is still higher than our provision which equated to approximately $0.65 million.

The revised proposal also includes new information on Aurora's analysis of the various localised issues, and the extent to how the non-network and network projects will relieve these[7]. Aurora considers that this information shows that the non-network solution is not sufficient on its own to alleviate some of the localised issues.

[3] Contained in AE055 – the Futura report
[4] AE128, pg 9, AE131, pg5
[5] AE131, pg 7
[6] AE131, Table 1
[7] AE131, Section 9

***Discussion***

We have reviewed the additional information in the revised proposal. We consider that there are three main issues to consider.

The first concerns our original view that the load relief reduction through the non-network solution was sufficient to alleviate the localised issues. We have reviewed the analysis presented in Aurora's revised proposal[8]. These results suggest that the most significant network constraints not addressed by the non-network solution are voltage drop and loading issues. From this new information, it was still not clear to us why these issues would not be alleviated by the use of mobile generation and reactive support. Therefore, we have requested further clarification from Aurora on its assumptions in this analysis, particularly with regard to mobile generation[9].

Aurora has provided a response on these matters[10]. However, this response has not provided any significant further information. As such, it is not possible to confirm with any certainty the validity of Aurora's analysis. Nonetheless, we do accept Aurora's contention in its response that even if mobile generation could be used to alleviate these constraints, the additional costs for this solution would most likely be greater than the avoided costs of the network project assuming the revised costs[11].

Therefore, the second issue is whether Aurora's revised project is reasonable. Although it is not possible to do any independent analysis to test other route/technology options, Aurora's revised solution appears far more reasonable to us given it is now a significantly lower cost and involving a far more reasonable route. As such, we consider it far less likely that an alternative short-term solution (which may only avoid this capital cost over a 1 to 3 year period) would be found to be the optimal overall solution to the various issues. Consequently, we are satisfied that this revised network project and its forecast cost are reasonably likely to represent the prudent and efficient solution to address the localised issues.

That said, the revised solution involves a new feeder and the splitting of existing feeders. New feeder projects of this type should inherently result in reliability improvement as existing feeders are generally split, and so the proportion of customers per km of line reduces. Moreover, in the recent review we conducted of the Victorian DNSP proposals, for some projects reviewed, where we had suitable reliability data, it appeared that the economic value of these reliability improvements (via the STPIS) would be sufficient to fund a large proportion of the project[12]. Therefore, in the case of this project, we consider

[8] AE131, Section 9

[9] This was particularly important has Aurora has suggested that this had been disallowed in the AER draft decision, so it was not clear whether it was included in the analysis.

[10] AER063, Question 1 response

[11] Assuming the Aurora analysis is correct, the mobile generation would most likely need to be run for extended periods during peak times, rather than just being on standby. Therefore its operating costs could be high. See AER-063, pg 4.

[12] For example, see the discussion on pg 170, of our report to the AER associated with our review of the Victorian DNSP's proposals, "Report – Capital Expenditure -Victorian Electricity Distribution Revenue Review - Revised Proposals", dated 26 October 2010.

it reasonable to assume that there should be similar benefits. Consequently, even if the project is required as proposed, we consider that the demand component could be reduced to allow for this impact.

The third and final issue is the impact Aurora's revised network project and the above findings have on the justification for the non-network project that is deferring the need for the new Sandford zone substation. Our position in our original review was that these two projects were not mutually exclusive. Although we have now accepted that the non-network solution will not alleviate all the localised issues (i.e. the discussion above), we do not consider that Aurora has addressed our broader concerns that the economic analysis provided in the Futura report assumed that the benefits (in avoided capital costs) that justified the non-network solution were based upon the total capital cost of the overall project (i.e. the sub-transmission works discussed here plus the capital costs of the new substation). This still seems to be incorrect. Given our findings above, we still consider that the sub-transmission works should be excluded from the non-network justification, as these are not deferred by the non-network project.

The Futura analysis allowed for a total capital cost of $11.9 million for this overall project. Allowing for the $6.6 million for the original sub-transmission project, implies that the new substation project cost was only $5.3 million. It would appear to us that if this value is used in the economic analysis then the non-network project allowance would need to be reduced.

To assess this issue further, we have requested further details from Aurora on this Futura analysis and the substation capital cost[13].

Aurora has advised that the Futura capital cost did include the sub-transmission project and new substations[14]. Although this seems to be in error, Aurora considers that the analysis is still valid[15]. The reasoning for this is not clear; however, it appears to be because Aurora considers that the costs were not on the same basis in terms of scope.

We still have significant concerns that the non-network project may not be justified if only the new substation cost is allowed for. Our request included the assumed capital costs for the substation, but this was not provided by Aurora[16].

In our view, it would appear that the assumed capital cost must be in the order of $10-11 million. This amount is not unreasonable for the final development of the substation. As such, the Futura analysis may still be valid.

However, we consider that a staged development of the new Sandford zone substation, as Aurora has proposed for the new Brown Street zone substation (discussed below under the Kingston project), seems to be equally appropriate here. This alternative project would involve a single transformer and around three HV feeders as a first stage, with a second transformer and additional HV feeders as a later stage. This could be developed

[13] AER063, Question 2
[14] AER063, pg 4
[15] AER063, pg 4
[16] AER063, Question 2b

for around $5 million to be in service at the same time as the new sub-transmission feeders, and would appear to provide similar, if not better, reliability than the revised network / non-network solution but at a reduced overall cost.

In conclusion, we consider that this overall network solution ($6.5 million) could be used to develop the capex allowance, with the provision for the Sandford non-network project removed. This would still provide a revenue stream to undertake some non-network solution in the next period, should this be found to be economic with this reduced capital amount.

Given this is a significant change to our original report, we are not proposing that this amount be reduced further to account for a portion of the project that could be funded through reliability improvements likely to be provided by the new feeders. However, the AER could consider whether a further reduction is warranted – as discussed elsewhere, this could represent a material portion of the project.

### 2.2.2 Geilston bay

***Nuttall Consulting original findings***

The original Geilston Bay project involved the construction of a new feeder from Geilston Bay at a cost of $0.25 million. The original proposal indicated that the majority of costs would be incurred in 2016/17.

Our view, based upon Aurora's demand forecast, was that only 90% was justified as the demand component, with the remaining 10% able to be funded through STPIS or opex mechanisms. This view was based upon:

- our understanding that the project was required largely to relieve an existing heavily loaded feeder (26167) from Geilston Bay
- Aurora's feeder loading forecast, which indicated that this existing feeder would be loaded well past its planning rating by 2016/17, suggested a high likelihood of the need for the project at time proposed
- our view that some opex/reliability benefits would result from this new feeder (e.g. transfers and reliability via reduced customer numbers on exposed feeder).

The AER's demand forecast indicated a much lower growth rate at Geilston Bay (0.25% per annum compared to Aurora's 2.73% assumption). Therefore, we considered it reasonable to assume that Aurora may be able to defer this project beyond its proposed date, as feeder loading would be significantly lower. Consequently, we reduced the demand component to 33%, with the remaining 77% assumed to be funded through opex/reliability benefits

***Aurora revised proposal***

Aurora has not accepted this position in its revised proposal. Its two main contentions are as follows:

- As the existing feeder is already above its planning rating (as we acknowledged) then the project is required irrespective of the different demand growth assumed by the AER[17].
- Geilston Bay is supplied by two old transformers, manufactured in 1968. Given their present loading, which is above the firm rating of the substation, Aurora anticipates that these transformers will need replacing due to their condition at that time; however, the reduced loading achievable through the new feeder will allow their lives to be extended[18].

Aurora also noted that there was an error in its original timing for the project, stating that this should have been 2013/14 not 2016/17[19].

***Discussion***

On the transformer replacement issue, we accept that offloading heavily loaded transformers could increase their lives (or reduce the risk of failure). However, we believe that the information provided by Aurora indicates that the transformers are unlikely to be of a condition and loading that they would require their replacement at that time, without Aurora's planned off-loading.

We consider that there are a number of reasons to support this view.

- Aurora points to the Aurecon findings on the replacement needs of the transformer, noting that Aurecon stated that they may require replacement in 2013/14 due to their age[20]. However, we understand that this view was based upon relatively simple reasoning, relating the age of the transformers rather than actual condition data and remaining life modelling that Aurecon performed[21]. Condition testing of these transformers was undertaken in 2010, with the results provided by Aurora to us during our original review[22]. The findings of the tester at that time was that the condition of these transformers was acceptable, and specifically indicated that test results suggested that the insulation condition was better than may be expected.
- Aurora considers that the Geilston Bay transformers are heavily loaded, well above the firm rating of the substation[23]. However, we consider that this may be overstating the risks. The substation is above what Aurora calls it emergency rating (25 MVA)[24], but it appears that this is a fairly low emergency rating, as an increase from the name plate rating of 22.5 MVA[25] i.e. approximate 10% increase. In our

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17 AE128, pg 7, and AE132, pg 5
18 AE132, pg 8
19 AE132, pg 9
20 AE132, pg 8
21 For example, see the assumptions on transformer lives provided in the Aurecon report, AE046, pg 3
22 [redacted] AER018, provided with the Aurora email, dated 12/8/2011
23 AER132, pg 10
24 AER132, pg 10
25 AER132, pg 10 (defined as "continuous planning rating") and 6.10 of original RIN (defined as "name plate rating").

experience, it is more usual to expect something in the order of at least 20% increase of a long-term emergency rating to the name plate rating. As such, there may be further scope to load the transformers above that rating, with acceptable impact on their lives. Nonetheless, setting this issue aside, even if the substation could be above the emergency rating, it appears to be still operating normally well within the name plate rating. Therefore, under these normal circumstances we may not expect any appreciable advanced aging to occur. As such, the risk of load shedding on transformer failure may justify some action, but the age/condition does not appear to be a driver.

On the feeder overload issue, we do not dispute Aurora's contention that the feeders are presently heavily loaded, and feeder loading data provided in the original and revised proposals indicates that feeder 26167 is currently above its planning rating.

Nonetheless, the reasoning for our position in our original review was that, based upon Aurora's view of the forecast loading on the feeder, Aurora appeared to be proposing that it could manage that feeder loading to 2016/17. We assumed that this position must represent prudent and efficient management actions by Aurora[26]. Therefore, as the AER's load forecast indicated that the feeder loading in 2016/17 would be much lower than that assumed by Aurora, it seemed reasonable to us to assume that whatever actions or risks Aurora was planning to take to manage the overload to 2016/17, those same actions or risks would most likely result in a prudent and efficient deferment of the project under the AER's revised forecast.

Significantly, the Aurora revised proposal now states that there was an error and the project was always planned for 2013/14. As such, it would now appear that Aurora only considers it will need to manage the apparent risks until this date. Applying a similar reasoning to that in our original review, it is worthwhile considering the difference in the loading up to this revised date.

With regard to the feeder loading, data with Aurora's original proposal indicated that Aurora forecast the feeder loading to be 5.8 MVA in 2013, which is 0.8 MVA or 16% above the planning rating of 5.0 MVA[27]. This was based upon an actual maximum demand of 5.2 MVA in 2009 and a forecast growth rate of 2.73% per annum. The feeder loading was forecast to be 6.5 MVA by 2017.

Feeder loading data provided by the AER, based upon its revised forecast for its draft decision, forecast the feeder loading to be 5.2 MVA in 2013/14, and still only 5.3 MVA by 2017[28]. This was based upon a slightly lower adjusted feeder loading for 2009 (presumably due to weather adjustments), and a much lower growth rate of 0.25% per annum.

[26] There are many factors that could mean the risks were not as high as appeared simply from the level of overload suggested by Aurora's, ranging from permanent or temporary transfers to operational ratings usable at times of maximum demand being higher than the planning ratings.

[27] NC - NW-#30201055-v1-2010_Feeder_Loading_-_PD_Data.xls (confidential)

[28] Provided in an email from the AER, dated 14/9/2011

Based upon the AER forecast, it would appear that Aurora may still be able to manage the overload throughout the next period as it will not exceed the level Aurora originally considered it would be at the revised project time.

However, in Aurora's revised proposal it states that the feeder load is forecast to be 5.8 MVA in 2012, increasing at around 0.1 MVA per annum after that (growing at around 2% per annum)[29]. If this is the case, then it would appear that the risks are similar to those in the Aurora original proposal, which we largely accepted.

We have requested further information from Aurora on its feeder load forecast and how it intends to manage the risks associated with the apparent overload[30]. Aurora has not provided any significant new information in response to this request. It appears however that it has simply reused its original feeder forecast.

Therefore, should the AER accept Aurora's revised forecast for this feeder we consider that the AER should revert back to the proportions we determined for Aurora, based upon the Aurora forecast, in our revised report. However, should the AER maintain its demand forecast for Geilston Bay as it applied for the draft decision, we see no reason to change from the proportions we advised in our original report for that demand level.

### 2.2.3 Gretna

***Nuttall Consulting original findings***

The original Gretna project involved the conversion of part of the network in that area to an alternative voltage at a cost of $1.2 million in the next period. The original proposal indicated that the majority of these costs would be incurred across the last 4 years of the next period[31].

We did not include this project as part of our detailed review. As such, the overall reinforcement allowance would have been based upon the findings of an alternative conversion project at Richmond that we did review. The finding here was that only 25% was justified due to demand growth. The remaining component being the efficiency-benefit.

***Aurora revised proposal***

In Aurora's revised proposal it considers that the driver for this project was not demand, but related to the condition of the transformers at Gretna[32]. As such, it considers it was in error classifying this in reinforcement and has classified it as non-demand in its revised proposal.

***Discussion***

Based upon Aurora's revised position, it appears that it has accepted that the demand driver for this project is not material. As this project was not included in our original

[29] AE132, pg 8
[30] AER063, Question 3 (Geilston Bay, Question 1, in Aurora response)
[31] Based upon cost data in Aurora's proposed program of work spreadsheet.
[32] Aurora revised proposal, pg 48

detailed review, we have considered whether or not the condition of the existing transformers support some project being undertaken.

We have requested further evidence from Aurora to support its claim that these transformers will be in such a condition in the next period that they will most likely require replacement[33].

Aurora has provided a number of test results for these transformers[34]. We have assessed these results and do not consider that they indicate that the transformers will need replacing in the next period. While we accept that the results suggest that some oil reconditioning, drying and minor transformer tank maintenance may be required, importantly, the results associated with the insulation condition indicates that significantly advanced aging has not occurred. For example, for tests conducted in February 2011[35], the tester notes for one transformer that "results indicate the paper insulation aging condition is marginally worse than expected for a transformer operating at normal recommended nameplate temperatures and ratings." For the other, the tester notes that "(f)uran results indicate the paper insulation aging condition is better than expected for the nameplate age of the transformer."

Based upon this, given that Aurora appears to have accepted that the driver for this project did not have a demand component, we do not consider that any provision is required in the capex allowance for this project.

### 2.2.4 Kingston

***Nuttall Consulting original findings***

The Kingston project was not part of our original detailed review.

We understand that this project relates to the development of a new zone substation at Browns Road that was originally planned for 2012 i.e. the current period. This substation was part of a set of developments, including a new 33 kV injection point at Kingston, that were required to relieve various supply constraints in that area. These issues and the options to relieve them were assessed as part of a joint planning exercise undertaken by Transend and Aurora, involving a public consultation phase as required under the NER[36].

A later stage of this overall development is the new Blackmans Bay zone substations, which was assumed in Aurora's original proposal to be deferred via a non-network solution, and essentially accepted by the AER in its draft decision.

As we understand it now, for Aurora's original proposal the Browns Road substation was also assumed to be deferred beyond the next period via a non-network solution throughout the next period.

[33] AER063, Question 5 (Gretna, Question 1, in Aurora response)
[34] Attached to AE063
[35] [redacted]
[36] See Final Report: Proposed New Small Transmission Network Asset and Proposed Large Distribution Network Assets, Development of the Electricity Supply Network in the Kingston Area.

***Aurora revised proposal***

Aurora's revised proposal states that Aurora's revised 2011 load forecast indicated that the Browns Road zone substation cannot be deferred via a non-network solution for the length of time previously assumed[37]. Therefore, additional capex is required to develop the substation.

It is proposing a more limited project than that assumed in the joint planning analysis, involving[38]:

- a single 25 MVA transformer and modular switching station
- a new 33 kV sub-transmission circuit from the Kingston terminal station
- three 11 kV feeders.

Aurora estimates the cost of this revised project to be $5 million, as opposed to the cost of the original Browns Road development of $20 million[39].

***Discussion***

Based upon the material provided with the revised proposal, it was not clear exactly what the differences were between Aurora's original and revised proposal. Therefore, we requested further information to aid in our reconciliation between the two proposals[40].

Aurora has advised that it did not allow for any costs associated with the non-network solution in its original proposal[41]. As such, it would appear the revised proposal allows for the increase in capex without any offset elsewhere.

With regard to the underlying network issues driving the need for a project of some form, we have not assessed this matter in great detail. Given that Transend and Aurora have been through a public consultation exercise associated with this project, and possibly more importantly, the draft decision effectively assumed some action was being taken, it seems reasonable to us to accept that there is a need for something.

Furthermore, with regard to the revised network solution proposed, this appears to be a reasonable solution and cost; for example, we note that Aurora is proposing a minimalist radial type solution involving a single transformer and sub-transmission circuit, and only three new feeders.

With regard to the reason for the change from a non-network to network solution, Aurora's revised proposal states that its revised load forecast has caused the change in circumstances for this substation. However, it provides no detail of what the changes to the load forecast are and why. We have requested further information on this matter[42].

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[37] AE134, pg 1
[38] AE134, pg 3
[39] The reduction appears to be due to the one less transformer and sub-transmission circuit, and six fewer 11 kV feeders.
[40] AER063, Question 4a (Kingston, Question 1a, in Aurora response)
[41] AER063, pg 5
[42] AER063, Question 4b (Kingston, Question 1b, in Aurora response)

Aurora has advised that changes include, among other things,[43]:

- an allowance for an additional 1.5 MVA point load associated with potential major commercial developments
- load transfers
- the use of embedded generation.

It also notes that its expected costs for generation to relieve the overloads would be greater than the avoided capital costs of the revised project at its proposed in-service date[44]. This is due to Aurora's view that by 2015/16 the generators will need to be loaded through peak periods, incurring additional operating costs[45].

We have not been engaged to review the load forecast of Aurora; as such, it is not possible to say with any certainty whether this revised load forecast is reasonable. It does appear however that the assumption of the increase of 1.5 MVA point load is important, advancing requirements by 1 to 2 years.

Furthermore, the need to load up the embedded generators from 2015/16 appears critical also. Aurora considers that this is required because at this time the loading at Kingston will exceed the emergency rating of the transformers. This has the impact of increasing generation costs from approximately $218,000 to $413,000, and increasing by a further $100,000 each year after that date.

In our view, this may overstate the likely costs on the non-network solution for two main reasons:

1 As the load relief is expected from only two generators, it may be more efficient to only run the generators following the transformer contingency. This may require some operational measures (such as the use of short-term transformer cyclic ratings) and/or load shedding following a transformer outage, while the generators are loaded up.

2 We also note that the load forecast provided by Aurora is a 10% PoE forecast; as such, in 9 out of 10 years, the forecast should be lower than this. This may suggest that average running costs will be lower – although, this issue may be less significant as Tasmania, in general, does not have as significant a difference between the 10% and 50% PoE maximum demands.

As such, it may be that a non-network solution is still achievable at a lower cost than the network solution. This may however still require the fixed cost component (i.e. availability payments) of the non-network solution over the next period. These fixed costs may also increase year-by-year as the generators need to be available over a longer period due to

[43] See "Load management" section, "NW-#30260093-v1-Supplemetary_AER_response_Kingston_Zone.pdf", attached to AER063
[44] AE134, pg 3
[45] See "Load management" section, "NW-#30260093-v1-Supplemetary_AER_response_Kingston_Zone.pdf", attached to AER063

the growth in demand. The amount required may depend on whether or not the AER considers it reasonable to allow for the 1.5 MVA point load in 2013.

All that said, given that the network solution will cut into existing feeders, it may well be that the reliability improvements through this will justify the network project. This does however suggest that the provision in the capex allowance does not need to cover the whole network project.

Ultimately, how the AER treats this project with regard to a provision in the capex allowance needs to be seen in the context of the overall methodology it has used to derive the reinforcement capex allowance. This project is not associated with one of the areas that we selected for our detailed review. As such, in these circumstances, it would seem reasonable to us that the AER could simply treat Aurora's estimate of the capex associated with this project like all of the other unreviewed projects. In this regard, the provision in the capex would be calculated using the revised demand and efficiency components.

Finally, it is also worth noting that the Aurora information indicates that this development will remove the need for the Blackmans Bay development, stating "(t)he revised arrangement for a Kingston Zone Substation will also have the effect of deferring the proposed Blackmans Bay Zone solution to well beyond 2022"[46]. This suggests that the opex and capex allowances associated with the non-network project to defer the need for this development are no longer required. Should the AER allow for the Kingston network project, it may need to confirm that these other costs have been removed.

### 2.2.5 St Leonards

This project relates to the development of a new Transend terminal station. The Aurora project involves the staged construction of 10 new feeders, at a forecast cost to Aurora of $1.3 million in 2012/13[47].

This project was not part of our original review.

Aurora considers that the application of the demand component derived from the reviewed project, 43%, on this project is not appropriate as this project is 100% required, being a committed project by Transend and having passed the regulatory test[48].

We do not dispute that this project may be required as proposed. But do not consider that Aurora's suggestion represents the intent of the methodology we have applied. In this regard, the capex via the adjustments has to be considered at the aggregate level, not at an individual project level. For example, there may well be other projects that we have not reviewed that may have a demand component well below 43%.

The AER can consider the ability to apply this logic and methodology within its NER obligations. We have not undertaken a review of this project; nonetheless, we make the following observation on funding requirements for St Leonards.

[46] See "Load management" section, "NW-#30260093-v1-Supplemetary_AER_response_Kingston_Zone.pdf", attached to AER063

[47] AE128, pg 7

[48] Ibid

The Aurora component of the St Leonards project involves the installation of a number of new HV feeders to offload existing feeders. As has been noted above, our review of the Victorian DNSPs reinforcement projects found that such new feeder projects should inherently result in reliability improvement as existing feeders are generally split, and so the proportion of customers per length of line reduces. Moreover, in the Victorian review, for some projects reviewed, where we had suitable reliability data, it appeared that the economic value of the reliability improvement (via the STPIS) would be sufficient to fund a large proportion of the project. Therefore, in the case of this project, we consider it reasonable to consider that there should be similar significant benefits. Consequently, even if the project has a much higher likelihood of being required than suggested by the 43% demand component, this component is still not clearly unreasonable given the various funding streams for these types of project.

## 2.3 The revised maximum demand forecast

As noted in the introduction to this section, the AER has requested that we reassess the demand and efficiency components we derived for each project we reviewed, with regard to the maximum demand forecast associated with Aurora's revised proposal.

The approach we have taken is similar to the one we applied in our original report to assess the impact of the forecast the AER determined for its draft decision[49]. To undertake the review here, the AER has provided a spreadsheet detailing the forecast demand applicable to Aurora's HV feeders[50].

The table below provides the findings of this review. These finding need to be read in conjunction with the project discussions provided in the original report. The main technical matters associated with the projects are not discussed here. The project components provided in this table will need to be applied by the AER within the methodology used for the draft decision to derive the associated demand and efficiency capex components associated with reinforcement capex.

**Table 1 Project review comments based upon AER maximum demand forecast**

| Project | Finding |
|---|---|
| 9.4.1 Austins Ferry zone substation | **Justification not changed: demand component remains at 100%**<br>The timing mainly relates to loading of the Claremont and Bridgewater transformers. There is no significant change in demand to the draft decision. Therefore, the reasoning remains the same as provided for the draft decision. |
| 9.4.3 Richmond zone substation | **Justification not changed: demand and efficiency components remain at 33% and 67% respectively**<br>The reasoning remains the same as provided for the draft decision. |
| 9.4.4 Rosny zone | **Justification not changed: demand and efficiency components maintained** |

[49] Discussed in Section 5.7 of our original report.
[50] Provided in the email dated 14/3/2012

| Project | Finding |
|---|---|
| substation | **at 90% and 10% respectively**<br><br>The timing of the Rosny development is mainly related to loading at Rokeby (and Lindisfarne). Rokeby has a slightly lower maximum demand in the revised proposal. This increase suggests that project elements may be deferred, possibly 1 year from the draft decision.<br><br>The project is also intended to relieve some heavily loaded feeders at Geilston and Bellerive. The maximum demand of these feeders is higher in the revised proposal. This may tend to advance the need for some elements of the project.<br><br>On balance, it seems reasonable to maintain the components as those used in the draft decision. |
| 9.4.5 Sandford zone substation | **See project discussion above**<br><br>The change in demand in the revised proposal is not significant enough to affect the reasoning discussed in the section above on the Sandford project. |
| 9.4.7 Wesley Vale substation | **Justification not changed: demand and efficiency components remain at 33% and 67% respectively**<br><br>The reasoning remains the same as provided for the draft decision. |
| 9.4.8 Wynyard substation | **Justification not changed: demand component remains at 100%**<br><br>The timing of this project is based upon three feeders supplied from Burnie. Demand is higher for these three feeders than assumed for the draft decision (returning to levels similar to Aurora's original proposal). However, the reasoning remains similar to that provided for the draft decision. |
| 10.4.1 Bridgewater | **Justification stronger: demand component reduces from 70% to 50%, efficiency changes to 50%**<br><br>This project addresses three feeders. These three feeders have a slightly lower maximum demand in the revised proposal. This suggests that project elements may be deferred, possibly 2 years from that assumed for the draft decision. This reduction however is still above Aurora's original forecast. Therefore, although the justification is stronger, it should be between the components derived for Aurora's original forecast and those for the draft decision. |
| 10.4.1 Chapel St | **Justification stronger: demand component reduces from 10% to 0%, efficiency changes to 100%**<br><br>This project addressed four feeders. The loading of these feeders is forecast to reduce during the next period. As such the justification is even stronger now. Given only one feeder is forecast to be overloaded, but this is reducing, then it seems reasonable to assume that the demand-related issues can now be managed without the need for capex. |
| 10.4.1 Devonport | **Justification not changed: demand and efficiency components remain at 33% and 67% respectively** |

| Project | Finding |
| --- | --- |
| | This project addresses two feeders. The loading is slightly lower in the revised proposal, but the reasoning remains the same as provided for the draft decision. |
| 10.4.1 Geilston Bay | **Justification weakened: demand component increased from 33% to 90%, efficiency changes to 10%**<br><br>This project addresses a single feeder. The loading in the revised proposal is similar to Aurora's original proposal. Therefore, the demand component should reflect the findings of that review. |
| 10.4.1 Hobart sub-transmission | **Justification weakened: demand component increases from 25% to 33%**<br><br>The project feeder overloads are not directly a driver of this project. However, as the project is driven by the loading at Lindisfarne, which is forecast to grow by a much higher rate in the revised proposal than assumed for the draft decision. This increase returns loading levels back to those similar to what Aurora allowed for in its original proposal. |
| 10.4.1 North Hobart | **Justification strengthened: demand component reduces from 33% to 10%, efficiency changes to 90%**<br><br>This project is related to the loading of three feeders. These three feeders have a slightly lower maximum demand in the revised proposal, due to a lower growth rate. This increase suggests that project elements may be deferred, possibly by another 2 years from the draft decision. |
| 10.4.1 Sandford | **See project discussion above**<br><br>The change in demand in the revised proposal is not significant enough to affect the reasoning discussed in the section above on Sandford. |
| 10.4.1 Sandy Bay | **Justification weakened: demand component increases from 33% to 90%, efficiency changes to 10%**<br><br>This project addresses four feeders. The demand in the revised proposal is forecast to grow – this reverses the reduction assumed in the draft decision. The growth however is not as high as assumed by Aurora in its original proposal. |
| 10.4.1 Smithton | **Justification not changed: demand and efficiency components remain at 70% and 30% respectively**<br><br>The loading is slightly lower in the revised proposal; however, the reasoning remains the same as that provided for the draft decision. |
| 10.4.1 Ulverstone | **Justification strengthened: demand components reduced from 90% to 70%, efficiency changes to 30%**<br><br>The loading is slightly lower in the revised proposal, due to a lower growth rate. This growth rate is now quite low – 0.2% per annum. As such, it may be expected that any worsening of loading issues can be managed more easily without increasing risks. |

# 3 Non-demand capex

## 3.1 Overview of original review and Aurora's revised proposal

For our original review, we aggregated the three RIN categories *reliability and quality maintained*, *reliability and quality improved* and *regulatory obligations* to form non-demand capex. This non-demand capex category was then disaggregated into the following three categories for our review:

- **Replacement,** which allowed for the replacement (or upgrade) of assets to account for non-demand related matters, such as asset condition, safety, or environmental risks and obligations
- **Power Quality**, which allowed for the upgrade of assets to comply with power quality obligations
- **Reliability**, which allowed for the upgrade of assets to directly address customer reliability concerns (and associated operational issues or other efficiency matters).

Our review of non-demand related capex included:

- comparative analysis of Aurora's non-demand capex against the equivalent capex of the Victorian DNSPs
- replacement modelling, using the AER's repex model
- analysis of Aurora's capex trends
- the detailed review of Aurora's asset management plans and forecasting methodologies associated with non-demand capex.

The high-level analysis and repex modelling indicated that Aurora's non-demand capex was significantly higher than the Victorian DNSPs. Furthermore, our detailed reviews found that a number of programs were not justified with regard to maintaining service levels, or their capex would be justified from resulting reliability improvements and/or reductions in existing levels of operating, maintenance and capital expenditure.

Our adjusted forecast was developed from the findings of our detailed review, whereby we allowed for the programs (or parts of) that we considered were sufficient to maintain reliability and quality. We also advised the AER of the programs and component of capex that we considered would need to be justified from reliability improvements and/or other expenditure savings.

We understand that the AER accepted our findings, and used these to determine its non-demand capex forecast in its draft decision.

Aurora's revised proposal has accepted our adjustments for the programs we allocated to our power quality category. It has also accepted some of our adjustments we made to our replacement and reliability categories. However, it has also challenged a number of our findings with regard to these two categories.

The AER has requested that Nuttall Consulting reviews the technical matters raised by Aurora in its revised proposal.

These matters are discussed in turn below, in terms of our replacement and reliability categories.

Before turning to these matters, it is important to stress that we did not consider that our original position on non-demand driven capex would materially change opex requirements from existing levels – other than the specific opex adjustments that we noted in our original report. In the program reviews discussed below, we will discuss the relationship of our revised findings on capex with opex requirements, based upon the new information provided. For the other programs that Aurora has accepted in its revised proposal, we do not consider that further opex increases associated with these programs are warranted, and do not discuss this further below.

## 3.2 Replacement

### 3.2.1 Overview

As noted above, our replacement category capture programs that we considered were related to non-demand matters. Effectively, these are the programs we considered were required to maintain performance levels and comply with obligations (excluding power quality and effects of demand growth). To undertake our detailed review, we assigned each of Aurora’s programs to one of the following eleven asset categories:

- poles
- conductors
- underground cables
- services
- distribution transformers
- distribution switchgear
- distribution other assets
- zone transformers
- zone switchgear
- zone other assets
- other.

The majority of Aurora’s programs allocated to each of these categories were reviewed. We made a number of adjustments where we considered that Aurora had not adequately justified the capex associated with each program.

As noted above, Aurora has accepted some findings. However, it has challenged our findings with regard to adjustments we recommended to the following four asset categories:

- poles
- underground cables
- distribution transformers
- distribution switchgear
- zone substation transformers.

Aurora disagreed with the use of the repex model, and made a number of specific comments on its validity.

The following sections discuss our revised review of the four programs listed above and our use of the repex model.

### 3.2.2 Poles

***Nuttall Consulting original review***

In Aurora's original proposal, Aurora was forecasting a large increase in capex to replace or stake poles in the next period from levels it had occurred in the recent past (i.e. pre-2009/10. The primary reason for this increase was due to the level of pole replacements that Aurora anticipated would be condemned as a result of the routine pole inspection cycle.

We did not accept Aurora's forecast capex associated with these programs, and recommended that this should be reduced to reflect the linear trend in expenditure (excluding 2009/10).

The basis for this view was:

- apparent inconsistencies in the Aurora data, covering:
  - our estimate of Aurora's forecast condemnation rates were above what we may expect for the long terms average
  - we did not consider that the type of pole used by Aurora was a sufficient justification for this difference, given the treatment processes it applied
- we considered that the forecast volume should be more reflective of historical volumes
- we did however allow for a modest increase, by allowing for the linear trend in historical expenditure (excluding 2009/10).

We also noted that this finding was broadly in line with our repex modelling, where we found Aurora's current lives were shorter than the Victorian DNSPs.

***Aurora revised proposal***

Aurora's revised proposal has not accepted our position on poles, and raises a number of issues with our reasoning[51], covering:

- we adopted an incorrect asset life
- ignoring the lower class of timber used, and misunderstanding the treatment process
- ignoring 2009/10 expenditure.

It also stated that the reduced expenditure for pole replacements in the AER's draft decision did not consider the impacts on risks to public safety.

Aurora also disagreed with our use of the repex model in assessing the poles category. However, we do not consider that the repex model played a significant role in our final recommendation. The reference to the repex model findings in the write-up of our detailed review was just to draw the similarity between the two findings. The final recommendation was based upon the detailed review findings. As such, we do not consider that these views are particularly relevant to our original review or the further review discussed below.

***Discussion***

Before turning to each of the issues raised by Aurora, we consider it important to explain the rationale behind our original position further. The primary consideration in our reasoning was the apparent step increase and high rate of growth in capex from actual capex in the current period. This increase was above the trend in capex.

Furthermore, this increase did not appear to be supported by the information that was provided by Aurora on pole condemnation rates. This showed a forecast trend of increasing numbers of condemned poles that was in excess of the actual trend. The forecast trend in condemnation numbers was below that of the trend in capex however.

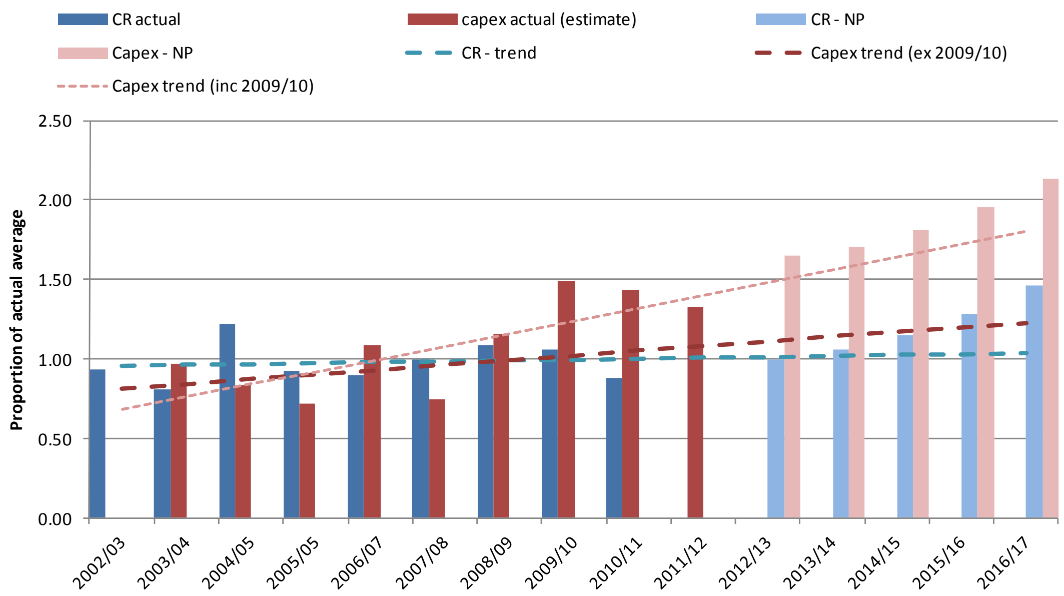
This can be seen in the figure below[52]. This figure shows actual[53] and forecast pole condemnations and capex. To put both on a similar scale, the quantity of each is provided as the proportion of the average of the actuals over 2003/04 to 2009/10. This figure also shows the linear trends in actual condemnations and capex taken forward into the next period.

[51] A121-Aurora Response-Pole Replacements

[52] This is based upon condemnation numbers provided in "NW-#30205201-v1-REPOL_Replace_Condemned_Poles_Volumes_ Analysis" (confidential) and the capex we allocated to the poles category.

[53] Note, for capex 2010/11 and 2011/12 were estimates for the last two years of the current period.

**Figure 1 Pole condemnations and capex**




The figure shows the points noted above, namely the capex step up from the trend and condemnations increasing above the trend. This figure also shows that the large step increase in actual 2009/10 capex has a large impact on the capex trend. If this year is removed, the trend in capex is much lower.

In addition to the above, we also considered that the replacement lives suggested by the forecast condemnations in the next period were too low. We did not believe that replacement requirements would change to that degree, and the implied lives were not in line with what was being achieved by other DNSPs. We also did not consider that the type of pole used by Aurora was a sufficient reason for this forecast trend in condemnation rates and capex.

Taken together, this suggested the forecast capex was too high. There was a range of possibilities of what the forecast capex could be. This included simply the average of the historical actual capex, to allowing for the trend in condemnation rates, to allow for the trend in capex. Given the findings of our repex modelling, which did support increases, we considered it reasonable to allow for some increase. The trend in condemnations appeared possibly too low. However, noting the significance of 2009/10 on the capex trend, we considered the trend in capex, using this year, was too high. On balance, we considered the trend in actual capex excluding 2009/10 was a reasonable position. This allowed for a modest increase in the recent trend in condemnation rates, but not as high as forecast by Aurora.

With this in mind, the three issues raised by Aurora are discussed in turn below.

Incorrect asset life

Aurora contends that we had incorrectly calculated the average asset age based on the projected replacement rates. In our original report, we stated that Aurora's condemnation forecast suggested future condemnation rates would increase from the current period to 4.0% - 5.3% over the next period. We also stated that we would expect to see condemnation rates of between 2% and 3 %, which would imply service lives of between 30 and 50 years based on our experience reviewing pole populations in NSW, Queensland, South Australia and Western Australia.

This comment by Aurora is correct. The condemnation rate forecast by Aurora for wood poles is 3.3% in the final year, which equates to an average expected life for wood poles of 33 years. The average condemnation rate Aurora has forecast for the next regulatory period is 2.45%, indicating a life of 41 years[54].

We do not believe that this arithmetical error alters the position in our original report. These lives are more in line with those we noted in our original report, but these are still at the low end of what we would expect.

To support its views, Aurora has also supplied the results of Weibull analysis it has undertaken to assess the distribution of the lives of poles it has replaced[55]. This analysis indicated that, based on historical pole data, Aurora's poles have a mean life of 55.47 years. Based on this mean life, we would expect to see a pole condemnation rate of approximately 1.8%.

Based on Aurora's wood pole population of 222,904 poles and its inspection cycles of 3.5 years, this equates to 1146 poles per annum requiring replacement. Aurora's average pole replacements from 2002/03 to 2010/11 (last full year of available data) average were 1281[56], equivalent to approximately a condemnation rate of approximately 2%. This condemnation rate aligns with the condemnation rate expected from the Weibull pole analysis and with our experience within Australia where 2% is around the normally expected condemnation rate for poles inspected regularly and treated during each inspection cycle.

Therefore, while we do not find any fault with the Weibull analysis, we do not consider that this impacts our findings.

We note Aurora has suggested that the lower lives implied by its forecast are indicative of the advancing age of the overall population[57]. Although this statement is generally correct, in our experience, the average age of the pole population is more significant than individual pole ages on pole population condemnation rates. Aurora has stated that during 2008/2009 4074 timber poles and during 2009/2010 4167 timber poles were purchased. Poles used for replacement during the corresponding periods were 1267 and 1277 indicating that 70% of the poles purchased were used for new construction works.

[54] These calculations are based on the information provided by Aurora in NW-#30205201-v1-REPOL_Replace_Condemned_Poles_Volumes_ Analysis (confidential).
[55] AE117-Aurora Power Poles Weibull Analysis
[56] NW#30205201-v1-REPOL-Condemned_Poles_Volume_Analysis (confidential)
[57] AE121, pg 3

As such, we may expect that the recent average age of the pole population is fairly stable – if not reducing.

In summary, although we accept that there was an error in the forecast lives we quoted in our original report, we do not consider that this impacts our overall findings. The Weibull analysis supplied by Aurora and the average pole replacement rate over the period 2002/03 to 2010/11 both support our assertion that a condemnation rate of 2% for the Aurora pole population is a reasonable forecast for the next regulatory period. In addition, we would not expect this rate to increase over the next period to 3.3% as assumed by Aurora in determining its forecast.

Type of pole and treatment

Aurora has stated that it only uses durability class 3 and 4 timbers for CCA treated poles, whereas on the mainland class 1 and 2 durability class timbers are used. It considers that this explains why the lives for its poles should be less than the mainland. However, we rejected this argument as we considered that the CCA treatment of these poles would result in similar lives.

As alluded to in the introduction to this discussion, the implications of pole types and treatments is not directly relevant to our overall findings, as this in itself does not explain the increases in the Aurora forecast from actual levels. Nonetheless, we still do not consider that this matter is as significant a differentiator to the DNSPs as proposed by Aurora.

We note that Aurora states that only the sapwood (outer layers) of hardwood poles can be pressure impregnated with CCA, and this means that the heartwood (inner core) is not treated. It considers that this can allow the inside of the pole to rot, reducing its life. These statements made by Aurora are correct but they apply to all pressure-impregnated treated hardwood poles, irrespective of the class of timber being used as only the sapwood of hardwood poles can be treated.

Furthermore, we agree that the treatment of softwood poles is different, as the entire wood of softwood poles can be treated by CCA. However, the engineering assessment carried out during ground line maintenance inspections typically involves measuring the outside diameter and internal diameter of the remaining sound wood at the groundline. The outside diameter of the remaining sound wood has the most significant impact on the strength of the pole; hence, the importance of preserving the sapwood of CCA impregnated hardwood poles. Whilst centre rot has to be monitored, the preservation of the outer rim of the pole is most important in maintaining adequate service lives. Hence, the industry practice of applying preservatives, such as Preschem Biogard, to the outer surface of poles and heartwood during the ground line maintenance process[58].

[58] Preschem rods are inserted into the inspection holes bored into the heartwood during the ground line maintenance procedure and a Preschem wrap is applied to the outer surface of the pole at and below groundline prior to backfilling the inspection excavation.

Aurora also stated that Tasmania was “wetter” than say central Victoria[59], but the Weibull analysis supplied by Aurora indicates that the average mean life of the Aurora pole population is 55.47 years which is similar to the average lives being achieved on the mainland including those pole populations situated in areas of both high rainfall and high humidity[60].

Ignoring expenditure from 2009/10

Aurora considers that we should have allowed for 2009/10 when estimating the forecast capex for the next period. It does not consider that the level of storms impacted pole replacement costs that year, as it considers we assumed. Rather it considers that the increase in capex in this year over the previous years was more reflective of the aging of the asset base.

Firstly, it is important to note that our detailed review included all data supplied by Aurora up until 2010/11, which appeared to be the last year where full year data was available.

As noted in the introduction to this discussion, it is true that 2009/10 was excluded from the trending we used to calculate the provision for poles. This was done partly as we considered that costs in that year may have been impacted by very extreme storms that occurred. However, more importantly for the poles category, we did not consider that the large increase in capex in that year reflected the broader trend in condemnation rates. As noted above, a linear trend in capex using 2009/10 would have resulted in a far greater rate of increase than historical condemnation rates suggested (even allowing for 2010/11).

For example, the growth rate in capex we allowed for was nearly 3% per annum. The condemnations data indicates a growth rate (via the linear trend) in condemnations of around 0.5% per annum - much lower than we allowed for. If we used the 2009/10 capex figure, the growth rate (via the linear trend) would increase to around 5% per annum. This is a 10-fold increase over the condemnation data figure.

For this reason, we still do not consider that the 2009/10 figure should be used, as we already consider that our position is most likely conservative.

Impacts on risk to public safety of reducing pole expenditure.

As noted above, Aurora has also suggested that the reduction in pole replacements through the AER’s draft decision may impact public safety.

Our review has sought to determine the prudent and efficient level of expenditure that we consider reasonably reflects Aurora’s practices. Our suggested reduction is based upon our view that Aurora’s forecast overstates the number of poles that are likely to need to be replaced, based upon these practices. We are not suggesting that these practices or risk levels need to change.

[59] AE121, pg 4

[60] This is, in all probability, due to the fact that the methods used to apply the preservatives including sealing the inspection holes with plastic plugs and wrapping a sealing tape around the top of the Bioguard sheeting just above ground line limits the leaching effect of rainfall.

In reality, the number of condemned poles may well vary from this forecast – up or down. The processes, procedures and work practices adopted to ensure the quality and security of supply, workplace safety, public safety, all compliance issues and statutory obligations, corporate obligations and aspirations, etc remain the responsibility of Aurora during the next period.

As such, we do not consider that this comment is relevant to our review findings.

Impact on opex

As noted above on the impact on public safety, our suggested reduction is based upon our view that Aurora's forecast overstates the number of poles that are likely to need to be replaced based upon current practices. We are in no way suggesting that current inspection practices need to change, resulting in increased opex. Neither are we suggesting that material increases in defective or condemned poles need to be maintained on the network. As such, we are not anticipating increased fault response costs due to our reduction.

Therefore, we do not consider that our position on pole replacement capex will have a material impact on existing routine maintenance costs.

Overall findings

Based on the data provided by Aurora and our extensive experience reviewing pole management programs on the mainland, we consider that our original findings are still valid.

With regard to our comments in our original report on the implied life of Aurora's replaced poles, we accept that we calculated this incorrectly. However, we do not consider that the additional information provided by Aurora, including its Weibull analysis, suggested that this impacts our overall findings.

We also acknowledge the differences in pole types between Tasmania and the mainland, and implications this has on treatments. Although, in this case, we consider that the impact on lives due to these differences is probably far less significant than suggested by Aurora.

Nonetheless, we do not consider that either of these points raised by Aurora – even if valid to some degree - change our primary view that Aurora's historical condemnation rate data does not support as significant an increase in pole replacement capex as forecast by Aurora. It is this relative increase in the forecast condemnation rate that is our primary concern, rather than the absolute level (which is reflective of the assumed life).

Therefore, we still maintain that projected expenditures for the pole replacement for the next regulatory period should be based on historical experience, allowing for the historical trend.

We note that there could be some case to include the 2009/10 expenditure data in calculating the trend, which we considered should be excluded from the calculation. However, as noted above, in the case of Aurora, the historical condemnation rates are showing a much lower increasing trend than that seen in the capex. This divergence would only increase further if we allowed for the 2009/10 expenditure when calculating the trend. As our current methodology to calculate the expenditure increase already significantly overstates the condemnation rate increase, we consider that our original forecast is most likely overstating requirements. Therefore, we do not consider it is appropriate to allow for this year in these circumstances.

### 3.2.3 Underground cables

***Nuttall Consulting original review***

In Aurora's original proposal, Aurora were forecasting an increase in capex associated with eight programs that we considered were related to the underground cable category.

We accepted that the majority of these programs were reasonable. However, we considered capex associated with two of Aurora's programs should be reduced as follows.

- the LV underground cable replacement program (excluding the CONSAC replacement program), where we considered that the capex should be removed
- the high voltage cable underground replacement program, which we considered the forecast should be reduced to reflect the historical costs and budgets.

In both cases, we considered that Aurora had not provided sufficient data that supported the need for the replacement levels forecast by Aurora.

Our detailed review of the LV underground cable replacement program was limited to evaluating the basis for the forecast expenditure as the justification for the program was not addressed in the documentation provided by Aurora.

***Aurora revised proposal***

Aurora's revised proposal has not accepted our position on these two programs.

For the both replacement programs, it considers that it requires the forecast expenditure as the proactive planned replacement under these programs is the more appropriate and cost effective than the reactive replacement[61][62].

It also considers that, due to its aging asset base:

- the provision of no capex for the LV cable program will "result in (an) outcome that would be detrimental to Aurora's business and its ability to adequately supply its customers"[63]
- the reduction in the HV cable program will not be "adequate to safely manage the assets"[64].

[61] AE115, pg 2
[62] AE114, pg 2
[63] AE115, pg 2
[64] AE114, pg2

***Discussion***

LV cables

For the LV cable replacement program, we have reviewed the additional information supplied by Aurora[65].

This information indicates that Aurora has 15 km of paper insulated, oil draining LV cable installed prior to 1960 and a further 207 km of paper insulated, mass impregnated non-draining (MIND) cable installed between 1960 and 1978. In total 222 km of paper insulated LV cable ranging in age from 30 to 50+ years.

Furthermore, the information indicates that non CONSAC LV underground cable failure rates have increased 17% over the preceding 10 years and cable faults have averaged 17 per year for the past two years. More importantly, there have been instances of multiple faults on 18 cables, ranging from 2 faults on 13 cables to 4 faults on 2 cables[66].

We accept that this failure data is indicative of deteriorating condition of the assets and also indicates that these cables are at or very near the end of their service lives.

Aurora proposes to introduce a paper insulated LV cable replacement management strategy by replacing these cables (or part thereof) where there are repeated occurrences of multiple faults. Aurora included $700,000 for the next regulatory period which was based on the replacement of 0.6 km of LV paper insulated cable over the period. As noted above, our previous recommendation was based on the lack of supporting information and data from Aurora to justify the inclusion of this allowance in the forecast capital expenditures.

Based on the additional information provided by Aurora, we accept that the LV paper insulated cables are at or nearing the end of their service lives. Furthermore, Aurora's forecast volumes of 0.6 km of cables, or sections of cables, exhibiting multiple faults appears reasonable.

There is no information available on historical expenditure on LV cable replacement. However, Aurora's forecast of $700,000 to allow for 0.6 km of replacement is not unreasonable based on the information provided. Therefore, we accept that provision should be made in the capex allowance, based upon Aurora's forecast for this program. This represents a reversal of our position in our original report.

HV cables

Turning now to the HV cable replacement program, we have reviewed the additional material provided by Aurora to support this program[67].

Previous information supplied by Aurora[68] indicates that Aurora currently has 30 km of paper insulated oil draining HV cable, 505 km of paper insulated mass impregnated non-draining (MIND) cable, 16 km of paper insulated oil filled cable, 6 km of submarine cable

[65] Contained in AE115
[66] See Table 2, in AE115
[67] Contained in AE114
[68] NW-#30199642-v1-Justification_REUGC _Replace_HV_UG_Cables (confidential)

draining type, and 15 km of submarine cable MIND. A total of 572 km of paper insulated HV cable in service aged between 20 to 90+ years.

The new information includes data on actual HV cable failures from 2000/2001 through to 2010/2011[69]. This data demonstrates a significant increasing trend, which we accept may be indicative of some cables nearing the end of their effective service lives.

In addition, the new information has provided data on the actual number of multiple faults on HV cable over the last 10 years[70]. This data ranges from 2 faults on 20 feeders to 4 faults on 2 feeders.

We also agree with Aurora's statement that older cables, particularly paper insulated cables, are more susceptible to multiple faults due to the stresses associated with the first fault and the associated repairs.

Nonetheless, we do not agree with a proactive cable replacement program, as it is almost impossible to predict which cable will experience faults[71]. We do however agree with the replacement of cables or sections of cable (i.e. between joint pits) once multiple faults begin to occur in close proximity on aged HV cables. Our view aligns with Aurora's stated objective of limiting price rises to customers during the next regulatory period. Our approach addresses the issue of multiple faults associated with disturbing old paper insulated cables by reducing the number of joints and the associated disturbance of the cables, and issues associated with moisture ingress following major faults which rupture the lead sheath.

We do however accept that our original allowance of $0.3 million (which was based upon the historical spend) is unreasonable, given the age profile of the paper insulated cables currently in service and the new information on the increasing trend in multiple faults. This supports Aurora's contention that some of the cable are nearing the end of their effective service lives.

Therefore, we consider that a reasonable capex allowance for the replacement of HV cables over the next period should also allow for the replacement of a submarine cable, as it appears one cable has been in service since 1914.

We note that Aurora's revised proposal for HV cable replacements is approximately $1.3 million, a reduction from the $2.3 million in its original proposal. Given the higher cost of submarine cable replacements, we consider that this revised expenditure is in accordance with our revised position discussed above. As such, we consider that Aurora's revised expenditure for this program is reasonable.

*Impact on opex*

With regard to the impact of these findings on opex, we consider that any impact on opex associated with these recommendations should not change opex levels. If anything, we consider that there could be some case that this will result in a reduction in opex, as the

[69] Figure1, S2.3, AE114
[70] Figure 2, S2.3, AE114
[71] That is, in these particular circumstances, we do not consider it would be prudent and efficient to replace HV cables prior to any faults occurring.

new cables should be fault free during their early service lives, and so may reduce the existing number of cable faults.

### 3.2.4 Distribution transformers

***Nuttall Consulting original review***

In Aurora's original proposal, Aurora were forecasting a large step increase in capex associated with nine programs that we considered were related to the distribution transformer category.

We accepted the majority of these programs, noting that much of the increase was to address significant safety issues that had recently been found.

We did however not agree with the forecast for one program associated with the replacement of 3-phase regulators. Our view here was that the increase in failure rates assumed by Aurora to produce its forecast was too high. We considered that the failure would be more in line with historical levels, and made associated adjustments to the forecast.

***Aurora revised proposal***

Aurora's revised proposal appears to have accepted our position in principle. However, it considers that it will need additional capex above the amount we proposed to allow for an increased number of spares and associated storage costs.

In this regard, Aurora's revised proposal states:

*"As Aurora currently holds one pair of 11 kV, 200 A units and one pair of 22 kV, 200 A units at its Training Schools which can be removed from the School and used as a spare if necessary, it is recommended that Aurora purchase the following additional spares:*

*1 One pair of 11 kV, 200 A single phase tanks;*

*2 One pair of 11 kV, 300 A single phase tanks;*

*3 Five pairs of 22 kV, 200 A single phase tanks; and*

*4 One pair of 22 kV, 300 A single phase tanks.*

*As Aurora currently does not have space in the existing bunded areas within its stores facilities, Aurora would also be required to extend the bunded area. It is estimated that the cost of extending the bunded areas at Cambridge and Rocherlea storage facilities is approximately $100k per site.*

*It is estimated that the cost of purchasing these spares is $550k and the cost of extending the bunded areas is $200k."*[72]

***Discussion***

We have reviewed the methodology used by Aurora to determine the number of spares requested and also the reasons Aurora has requested the additional expenditures[73]. We

[72] Pg 4, AE116 – Aurora Response – Replace Three Phase Regulators (REGMR)

note that, to date, Aurora has considered that holding only two pairs of the lower capacity single phase tanks is adequate to maintain satisfactory security and quality of supply. In addition, we noted in our original report that historically Aurora has replaced two regulators every five years.

Based on Aurora's historical risk profile and three phase regulator failure history, we accept that some further allowance to increase the number of spares may be necessary to provide reasonable reliability and quality of supply outcomes. However, we do not consider that Aurora has justified that such a significant increase in the holding of spares is warranted. In our view, their revised proposal would most likely represent a significant reduction in presently accepted risks.

In our view, the following are more-likely prudent and efficient assumptions that will maintain reliability and quality of supply (and associated risks) over the next period:

- the replacement of two three phase regulators over a five year period
- the availability of spare pairs of 11 kV and 22 kV 200A and 300A tanks.

This would result in the requirement to purchase an additional pair of 11 kV and 22 kV 300A tanks[74], as well as making allowances for the replacement of two three phase regulators over the next regulatory period. This would result in Aurora having spares for all 11 kV and 22 kV, 200A and 300A regulators.

As our original report recommended allowing $0.7 million for the replacement of two regulators over the next 5 year regulatory period based on historical failure rates, we accept that a further increase in capex is warranted to allow for these additional spares.

Based on the cost information provided by Aurora, which we consider is reasonable, we recommend an additional allowance of $70,000 for the purchase of these units. However, we do not consider that the additional costs proposed by Aurora for storage and bunding are reasonable. In our view, we consider that it is likely that Aurora would have sufficient space in its existing bunded areas for the storage of these two spares.

Therefore, our total revised recommendation for the replacement of three phase regulators is $0.77 million.

With regard to the impact on routine maintenance, our recommendation would have a very minor impact on these costs in so far as these regulators are usually not fitted with breathers. Therefore, intermittent oil tests would be required to ensure oil moisture content remains within acceptable levels.

[73] Contained in AE116

[74] Aurora currently holds one pair of 11kV 200A units and one pair of 22kV 300A units, so holding the additional 300A units would mean spares are available for all units currently in service.

### 3.2.5 Distribution switchgear

***Nuttall Consulting original review***

In Aurora's original proposal, Aurora were forecasting an increase in capex over longer term trends, associated with seven programs that we considered were related to the distribution switchgear category.

We accepted the majority of these programs. We did however not agree with the forecast for one program associated with the replacement of Expulsion Drop Out (EDO) fuses outside very high bushfire areas. Our view here was that this program was not supported by asset condition data, and a "business as usual" approach should be taken.

With regard to the replacement of EDO fuses in fire danger areas, we noted that the forecast expenditures for the replacement of older EDO fuse tubes in high and very high fire danger areas should be redirected to the program to remove expulsion type fuses from these areas. We considered that this represented a more effective and permanent solution to the fire-start problems associated with expulsion fuses. We also noted the following advice provided by Aurora in relation to the replacement of EDO fuse carriers by Boric Acid fuses. The program is a trial as part of Aurora's strategy to ensure that all control station EDO fuses that protect multiple transformers are replaced by a fire safe alternative, such as boric acid fuses, by 2020. The program has been extended to 2030 to align with Aurora's strategy of no price increases to the customer. Both these points were an observation; they were not intended to suggest an alternative allowance was necessary.

***Aurora revised proposal***

Aurora's revised proposal appears to have not accepted our position associated with EDO fuses outside very high bushfire areas. In this regard, it includes a capital allowance for an Expulsion Drop Out (EDO) fuse tube replacement program to replace switchgear at sites with a service life exceeding 10 years to manage the risk of EDO 'hang up' outside areas classified as high or very high fire danger[75].

The revised proposal also includes an additional capital allowance of $435,350 ($156,601 per year in very high fire danger areas and $278,749 per year for high fire danger areas) for the replacement of EDO with Boric Acid fuses. The original intention of this program was to ensure that there were no EDO fuse tubes greater than ten years old in the system by 2020 and to maintain a ten year replacement cycle[76].

***Discussion***

In relation to the proposal to commence a program of EDO fuse carrier replacements in areas outside those classified as either high or very high bushfire areas, we do not consider the commencement of a program aimed at ensuring that all EDOs located in lower fire risk situations have service lives limited to 10 years is reasonable. Moreover, we

[75] AE122- Aurora Response – Replace EDO Fuse Tuber (REOHS)
[76] AE123_ Aurora Response – Replace EDO Fuse Tube Replacements

do not believe that this would be the most cost efficient method of managing the fuse carrier “hang up” issue.

This view is based on the following:

- in our experience, many fuse carriers exceeding 10 years in service continue to operate correctly
- some carriers exhibit “hang up” characteristics before reaching 10 year service lives
- the rate of degrade of the fuse carrier tube depends on a number of factors including operating environment, materials used in its manufacture, age, etc
- many businesses manage their population of fuse carriers located in lower risk fire locations by inspection during routine line patrols, monitoring conditions after fault operations, and monitoring records of specific manufacturers performance
- although “sparkless” fuses are not a complete solution many businesses have switched to their use in order to better manage bushfire starts resulting from the correct operation of EDO fuses.

We therefore believe an approach based on replacing EDO fuse carriers identified as defective either by malfunction, inspection programs or analysis of specific manufacturer’s performance will result in the current risk profile accepted by the business over the previous 9 years being maintained.

Turning now to the second of Aurora’s program changes associated with bushfire risk areas, as stated in our original report to the AER, we consider the replacement of EDO expulsion fuses in areas of high and very high fire danger to be prudent. However as with all these programs, the optimum speed at which the replacement program is implemented is difficult to determine.

In addition, we continue to believe that the replacement of older EDOs in high and very high fire prone areas with new EDOs is at best a temporary measure that does not address all the issues specifically those associated with the sparks emitted during the correct operation of the fuse element. Therefore, we continue to support our previous recommendation in relation to the redirection of the capital allowances included for this part of the program to the installation of Boric acid fuses. We note Aurora’s intention to prioritise the Boric acid fuse replacements and agree with this approach to the issue.

We also note that Aurora has decided to extend this program out to 2030 in order to manage price impacts on customer’s accounts. We are fully aware that it is Aurora’s sole responsibility to manage the risks faced by the business and that our recommendations relate solely to what we consider to be prudent and efficient capital allowances based on the information provided.

We do not believe that we have been presented with any additional information to support increasing the capex allowance to allow the original volume of EDO fuse replacements to be substituted with Boric acid replacements. Rather, we restate the opinion expressed in our original report that the replacement effort could probably be more prudently directed towards the prioritised permanent solution to the issue, instead of the proposed "two prong" approach proposed by Aurora. In effect, replacing some of the higher priority areas with Boric acid fuses may result in the lower priority areas not being required in the next period to achieve the same risk outcome. For example, this prioritised approach could include ensuring the any EDOs protecting multiple transformers or spur lines are replaced ahead of EDOs protecting single transformers.

Based upon our review of the information provided by Aurora in its revised proposal, we do not consider that Aurora has presented any compelling evidence to support the increases in these two programs. Therefore, we do not consider that any change in our findings is warranted from those given in our original report.

With regard to the impact on routine maintenance, we believe that these recommendations would have minimal impact on opex. If anything, it may slightly reduce opex as a result of the reducing time spent trying to identify EDOs that have "hung up".

### 3.2.6 Zone substation transformers

***Nuttall Consulting original review***

In Aurora's original proposal, Aurora were forecasting a large increase in capex on zone substation transformer replacements.

In our review, we did not accept that there was a need for any provision in the capex allowance to cover age/condition related replacement of zone substation transformers. This view was based upon our detailed review of Aurora's information, including recent transformer condition test data. In our view, we did not consider that this data supported the need to replace any transformers in the next period.

We did however consider that if the allowance for the proposed transformer replacements was removed then a provision for at least one spare transformer should be included, as Aurora currently has no spare power transformers. We believed that this should enable Aurora to manage the risks associated with an aging power transformer fleet. We considered that a capital allowance of $1 million in 2013/14 should be sufficient for these purposes.

***Aurora revised proposal***

Aurora has accepted our position, in principle, in its revised proposal. However, it considers that it requires a far more significant amount to allow for spares. This appears to be mainly due to a far greater level of spares that it considers will be required.

In this regard, Aurora considers that it requires:

- to cover rural transformers[77]
  - four spare 22/11 kV, 5 MVA transformers ($2 million)
  - development of appropriate oil-contained secure site for storage ($160,000)
- to cover urban transformers[78]

[77] AE126

- three spare 33/11 kV 25 MVA transformers ($3 million) (plus an additional spare later in the period, when a spare is required)
- development of appropriate oil-contained secure site for storage ($650,000)
- one additional 33/11 kV, 25 MVA transformer be purchased in 2015 when the existing spare transformer is installed at Kingston ($1 million).

***Discussion***

Currently Aurora is managing its power transformer fleet without any spares. As noted in our initial review, we recommended that as the power transformer fleet ages this approach poses an increasing risk to the security and potentially the quality of supply in the event of power transformer failures. Hence, we recommended that Aurora be given a capital allowance of $1 million in 2013/14 for the purchase of at least one spare transformer.

We have reviewed the new information provided by Aurora[79], and in particular the methodology used to determine the recommended level of urban and rural power transformer spares.

We believe that accepting all of Aurora's spares requirements would result in very substantial reductions in the risks facing the businesses compared to its current tolerance for risks associated with the failure of power transformers. We also consider that this would be out of step with Aurora's stated aim of managing price impacts for its customers.

In our view, the reduction in risks would far exceed any expected increase that may occur due to the ageing of transformers. Important to this view is our previous review of transformer condition test data. As noted in our original report, and restated above, this test data did not suggest that any of the transformers being considered for replacement were likely to have insulation failure in the next period. Given this finding, the likelihood that this many spares would be needed during the next period must be very low indeed.

We do accept however that a further spare may be required to alleviate risks associated with the rural fleet. Accordingly, we consider that a $1.5 million provision should be made in capex allowance for the purchases of two spare power transformers, as follows.

1. one spare 22/11 kV, 5 MVA transformers estimated to cost of $0.5 million for rural zone substations; and
2. one spare 33/11 kV, 25 MVA transformers estimated to cost $1.0 million for urban zone substations.

In our view, these two spares should provide adequate coverage of the population of rural and urban transformers. We believe this provides a reasonable outcome, weighing the need to have spare transformers available within a reasonable time frame, the costs associated with managing the risks associated with power transformer failures, and the age and condition of the existing power transformer fleet.

[78] AE127

[79] Contained in AE126 and AE127

We do not recommend making any additional allowance for extending bunded storage facilities as we believe Aurora should be able to find suitable storage sites for two additional power transformers within its existing facilities[80].

With regard to the impact on opex, we still maintain the need for the additional opex provisions we noted in our original report in relation to the maintenance of the existing power transformer fleets i.e. cost to allow for the reconditioning of the oil.

Additional, the holding of these two spares may also increase opex due to the need to maintain the spare power transformer breathers and also carry out occasional oil tests to ensure moisture levels remain within acceptable limits.

### 3.2.7 The use of the repex model

As noted in the introduction, we used the AER's repex model to undertake a high-level assessment of a large portion of Aurora's replacement capex. This analysis found that Aurora's forecast was above benchmarks derived from similar models of the Victorian DNSPs prepared for the AER[81].

In its revised proposal, Aurora has disagreed with the use of the repex model.

The AER has requested that we provide comments on the following points raised by Aurora:

- the REPEX model is unreliable because it needs to be 'manipulated' to replicate historical experience
- the REPEX model does not account for differences in operating environments
- the REPEX model used non-CPI-indexed costs
- the REPEX model is not reliable as it assumes a normal distribution of asset failures around the standard life, while a Weibull distribution is more commonly used for replacement modelling
- the REPEX model is unreliable because it is overly sensitive to asset life assumptions.

***Discussion***

Before addressing each of the points raised by Aurora, we consider it important to note the following.

Although the findings of our repex modelling informed our view that Aurora's capex should be rejected. It was only one of a number of factors that led to this view – not least, the findings of our detailed review of the programs that underpinned Aurora's capex associated with the replacement category.

[80] Without inspecting sites, it is not possible to know this with certainty. However, as the risk of oil leaks in new transformers are very small, we consider it reasonable to assume that some suitable storage site could be found somewhere in one of Aurora's facilities.

[81] These models were used during the AER's most recent regulatory revenue determination of the Victorian DNSPs.

In determining the adjustments to develop the substitute allowance, we did not directly rely upon the results of the repex modelling. Instead, all adjustments made to the capex associated with the replacement category were based upon specific findings of our detailed review of the replacement programs.

This is different from our most recent review of the Victorian DNSPs revenue proposals, where the results of the repex model were used directly at times to develop a substitute allowance.

As such, whether or not the points raised by Aurora are valid – which we will go on later to say we do not consider them to be – we do not believe that this would change our view that Aurora's capex should be rejected and the specific adjustments we have advised to make a substitute allowance.

*the REPEX model is unreliable because it needs to be 'manipulated' to replicate historical experience*

Aurora's revised proposal makes a number of statements associated with its view that the model is not valid as it has to be manipulated to replicate historical experiences. The argument being put forward by Aurora is not fully clear to us, but appears to cover the following related points[82]:

- for the model to be valid it must replicate the behaviour of assets being modelled – there is no evidence that this is the case
- the model uses scaling factors and other adjustments to replicate some, but not all, aspects of historical asset behaviour
- the model has not been validated against the performance of real assets – rather it is manipulated to fit historical data – as such, it cannot be seen as a reliable estimator of future asset behaviour.

Based upon the above, it appears that Aurora is arguing that the repex model and our use of it is not valid as there is no evidence that it replicates the behaviour of assets and the past performance of assets. Unfortunately, in making these claims Aurora does not explicitly point to the evidence it has provided to support these views.

Nonetheless, this argument is presented in the document it has provided to support its forecast for pole replacement. As discussed above on our review of pole replacements, two of its supporting arguments against our position are:

- the Weibull analysis Aurora has done on past performance that supports its pole life – which we assume is presented to show that our calibration to historical performance was not valid
- our view that Aurora's lives should be similar to the Victorian DNSPs is not valid because of the different pole types and abilities to treat these different pole types – which we assume is presented to show that our benchmarking of Aurora to Victorian DNSPs was not valid.

[82] Based upon 2.4.1,

We do not believe that the information and discussions provided by Aurora to support these claims is not valid. In fact, with regard to the Weibull analysis it has presented, we consider that, if anything, this assists in validating the process we applied to calibrate lives to historical performance.

In this regard, the Weibull analysis suggests a mean life of 55.5 years based upon historical replacement levels[83]. Our process – albeit founded on an assumed normal distribution - determined a life of 55.7 years. This would appear to us to be a very good match to Aurora's analysis. Furthermore, as we will discuss further below, our running of Aurora's Weibull distribution through the repex model against a similar normal distribution found a 1% to 3% difference in the forecast capex in any year. Once again, we consider that this match is completely acceptable for the purposes we have used the model.

With regard to the different pole types Aurora uses and associated treatments, we have argued in the pole section above that we do not consider that these matters should impact achievable lives in a significant way.

Importantly, this benchmarking exercise has to be seen in the larger context of the overall review process. The findings of this benchmarking study are initially used as a guide to areas for the detailed review. The detailed review determines whether there are reasons things should differ from the model outcomes. This has occurred in our review, and adjustments have been made. As such, we consider it misleading to isolate the model findings from the overall approach.

Finally, we consider the characterisation of the approach we applied to calibrate model input parameters or deriving benchmarks from such parameters as "manipulation" is misleading. This suggests that adjustments were relatively arbitrary – effectively at our discretion – to ensure we can achieve an outcome. We do not believe that this is the case. The fact that our approach appears to correlate so well with Aurora's Weibull analysis – which is a well accepted approach to derive replacement lives from historical data - seems to support this view.

*the REPEX model does not account for differences in operating environments*

We consider that this point is simply an extension of the points on validity and verification covered in the discussion above. It is true that the process we have applied to develop a benchmark repex model of Aurora has not tried to account for all the differences in the operating environments of the set of DNSPs that have been used to prepare the benchmark model. However, this model has not been used in isolation to derive any capex adjustments.

Instead, as noted above, the output of the benchmark model must be seen in the broader context of our overall review approach. The findings of this model informed our detailed review. The detailed review considered matters associated with differences between operating environments.

[83] AE117, pg 2

We do not believe there is anywhere in our findings on the adjustments associated with replacement capex where we have not tried to consider Aurora's specific operating environment.

*the REPEX model used non-CPI-indexed costs*

We note that Aurora has stated that the AER has advised that historical costs used to calibrate the model were not adjusted for CPI[84]. As far as we are aware, that is not correct. The costs we used were based upon a spreadsheet of historical program costs provided by Aurora, which we understand were adjusted for CPI i.e. they were in real 2009/10 dollars.

If that is not the case then the forecast capex may be too low; however, we presume this must only amount to around 10%. For the reasons discussed above, this would have had no impact on our final position – which was based upon the detailed review.

*the REPEX model is not reliable as it assumes a normal distribution of asset failures around the standard life, while a Weibull distribution is more commonly used for replacement modelling*

Aurora considers that the model is not reliable as it uses a normal distribution rather than a Weibull distribution. As noted above on the validity of the models, Aurora has provided Weibull analysis of past pole replacement. This analysis fits a Weibull distribution to the volume of past replacement and survival of Aurora's poles.

We have previously provided some commentary to the AER on this specific point in response to similar comments made by the Victoria DNSPs[85]. Our response at that time was as follows:

- We did not disagree that a Weibull distribution is often used for reliability analysis, including replacement modelling. However, we considered that the use of a normal distribution was a reasonable approximation to make in the absence of the more complete data set that would be required to determine a more accurate distribution.
- In defence of our use, we also made the following observations:
  - a normal distribution is used in the similar model used by the UK regulator, Ofgem, and this model has been applied for around the last 15 years in the UK for regulatory purposes
  - one of the Victorian DNSPs had also assumed a normal distribution for the majority of the probabilistic modelling it has applied to support its proposed replacement expenditure.

We still consider that these points are valid. With regard to Aurora's Weibull analysis, as noted above, we consider that this supports the validity of a normal distribution rather than disproves its. To test this, we have been able to derive a normal distribution that

[84] AE121, pg 5
[85] Report – Capital Expenditure - Victorian Electricity Distribution Revenue Review - Revised Proposals, Pg 34

provides a close approximation to the Weilbull distribution that was provided by Aurora for poles[86]. These two different distributions were then assessed through the repex model using the age profile for one of Aurora's poles categories[87]. This analysis indicates the range of differences in capex, using the two distributions, of no greater than 3% per annum, with an average difference of just under 2%.

We consider that this demonstrates that a normal distribution can be a very good approximation to the Weibull distribution. Given that generally data is not available to derive such Weibull distribution – even Aurora did not have this analysis at the time of our original review – we still believe that a normal distribution is the best approximation to use in these circumstances.

*the REPEX model is unreliable because it is overly sensitive to asset life assumptions*

Aurora notes that for poles, an increase of 3.9 years in our benchmark model from the life in our calibrated model resulted in a $3 million to $4 million reduction in capex per annum[88]. This is equivalent to around a 7% increase in the life resulting in around a 40% reduction in capex.

We do not disagree that this is showing a high sensitivity of the change in capex to the change in life. However, we consider that this sensitivity is reflective of the age profile Aurora has provided and the standard deviation of the replacement life we have assumed.

We do not believe that this sensitivity, in itself, can be viewed as evidence that the repex model as an assessment tool is not valid. It may possibly suggest that a greater standard deviation should be considered. Given the point made above, that the repex model findings have not directly been used to develop Aurora's adjusted forecast, we do not believe that this changes our overall position. The AER could consider doing further investigations on this sensitivity issue however at a later date in order to inform future determinations.

## 3.3 Reliability

As noted above, our reliability category captured programs that we considered would need to be justified with regard to their reliability improvement and/or other savings in expenditure.

Effectively, these are the programs we considered were required to enhance performance levels (excluding power quality). Obviously, implicit in this is the assumption that these programs are not required to ensure compliance with mandatory obligations.

Programs we allocated to this category can be considered in terms of three types:

[86] To perform this we uses Excel's solver to derive the mean and standard deviation of the normal distribution that minimised the square of the errors between the two functions.
[87] Wood poles (CCA)
[88] AE121, pg 5

- local reliability programs – which was an Aurora reliability classification for programs aimed at specific areas where customers were considered to be affected by poor performance
- remote control and protection programs – which was also an Aurora reliability classification for programs aimed at performance in urban areas, and ensuring good industry practice with regard to protection and control
- other programs – which was a category we included to capture programs not explicitly identified as reliability by Aurora, but which we considered would need to be justified based upon their improvement on reliability or other efficiency benefits.

Based upon our detailed review of documentation provided by Aurora to support these programs, we considered that they appeared reasonable in principle, and constituted an appropriate solution to address possible reliability and operational issues. However, we considered that they should be considered as programs to *enhance* reliability and performance, not *maintain* them. This view was based upon our belief that our overall allowance for the replacement category should be sufficient to maintain reliability and performance, given it represented an increase over the longer term historical level.

As noted above, Aurora has accepted some findings. However, it has challenged our findings with regard to a number of programs. Broadly, Aurora considers that some of these disputed programs are required to maintain reliability. In other cases, it disagrees that the programs are related to reliability at all.

The following sections discuss our revised review of these disputed programs in terms of the three program types noted above.

### 3.3.1 Local reliability programs

***Nuttall Consulting original review***

Aurora's original proposal classified five capex programs as part of its local reliability programs[89]. This allowed for approximately $6.5 million over the next period. We considered all these programs were associated with improving reliability (and associated opex reductions). As such, we believed that a specific provision for these programs in the capex allowance was not required.

***Aurora revised proposal***

Aurora's revised proposal has accepted our view for one of these programs. However, Aurora considers there should be a provision for the other four[90]. Its view here is that these four programs are required to maintain reliability – not improve reliability as stated by the AER/Nuttall Consulting.

In supporting this view, Aurora considers that:

[89] See discussion in our original report, pg 125
[90] AE125, pg 2

- The replacement expenditure allowance is insufficient to maintain reliability[91]. Its key point here is that it considers that replacement expenditure is mainly focused on safety, and as such, these reliability programs are still required. It also noted the example of the new program to replace CONSAC cables, which we accepted in our original review, of which it considered has only a 1% impact on reliability[92].
- The programs are reactive in nature and so aimed at maintaining reliability following further deterioration of performance[93].

In addition to the above two technical matters, Aurora also raised other objections to this view that we consider to be more regulatory in nature. We have not been requested to address these regulatory issues.

***Discussion***

Aurora's reliability management plan describes these four programs as follows[94]:

- **PRREL** – to respond to general reliability issues identified through monitoring systems e.g. additional poles or delta spacing to avoid clashing, additional fault indicators, additional fuses, and network reconfiguration
- **PRTXI** – to respond to reliability issues resulting from frequent or repetitive operation of protection devices with a view to resolve repeating outages
- **PRREH** – to relocate/alter HV fuses, based upon the identification of radial areas that would benefit from short feeder sections to provide alternative restoration paths (the plan notes that this program has been developed based upon feedback from staff on areas requiring only minor augmentation, but providing greater interconnectivity, improving fault response and SAIDI)
- **PRSPT** – to minimise potential birds colliding with the distribution network, reducing outages, repair costs and reducing fire risks.

Based upon Aurora's description of the programs, it is clear that all these programs are primarily targeted at improving reliability from an existing level. Even if they are reactive in nature, as stated by Aurora, their effect will be to improve reliability from that which it was immediately prior to the works being performed.

Therefore, the key issue appears to be whether it is reasonable to expect that reliability will deteriorate through the next period if we exclude these programs entirely i.e. these programs are required in addition to replacement (and other expenditure categories) to only maintain reliability. The Aurora revised proposal suggests that the main drivers of replacement are safety, so will not have a great impact on reliability i.e. these additional programs are still required.

[91] AE125, pg 2

[92] It is not completely clear what the 1% relates to. Nonetheless, the main point that it has a minor impact on improving reliability is relatively clear.

[93] AE125, pg 3

[94] AE025, Section 10.4

We may accept this reasoning if replacement and reliability expenditure and customer reliability had been relatively constant recently. However, given the recent large increases in expenditure and significant improvements in reliability seen by Aurora, particularly over the current period, we do not agree with this view in Aurora's circumstances. In the current period, annual reliability data suggests that Aurora has improved its reliability considerably in terms of SAIFI. At the same time, it has approximately doubled its replacement capex from levels in the previous period, as well as implementing targeted reliability improvement programs (TRIPS - which are set to end in the current period) and the other reliability programs discussed here. Implicit in Aurora's position is that the TRIPs are the only programs improving reliability.

We accept that the targeted reliability programs should have significantly contributed to the improvement in reliability seen in the current period. However, given such a significant increase in replacement expenditure has also occurred, we consider that this expenditure also would have had a material contribution to the improved reliability. In this regard, we do not consider it reasonable to suggest that this scale of replacement would have contributed immaterially to improving reliability in the current period, irrespective of whether the main driver was predominately associated with reducing safety risk. We acknowledge the example of the CONSAC cable provided by Aurora, but consider that in general across all programs contributing to the replacement expenditure, they must have in aggregate also contributed to materially improving reliability.

Given this view, considering that we have allowed for a further modest increase in replacement expenditure, we do not consider that it is reasonable to assert that this allowance is insufficient to, at the very least, maintain reliability.

In making this claim it is worth noting that we understand that the AER has set STPIS targets at the average of past reliability (5 years), with only modest adjustments to allow for further improvements from the targeted programs (TRIPS). The AER has not attempted to determine any further improvements that may have resulted from the other reliability programs or further improvements resulting from increases in expenditure associated with the replacement (or reinforcement) programs. As such, if anything, our position above could be assumed to be fairly conservative i.e. actual expected reliability at the commencement of the next period should be better than the STPIS targets.

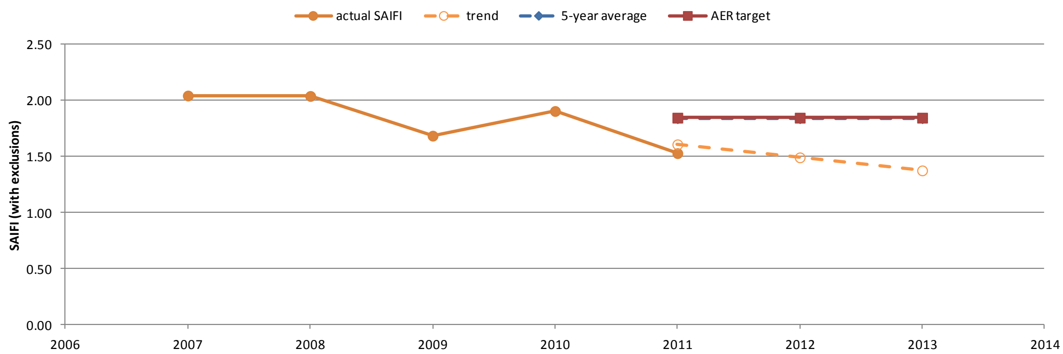
To demonstrate this further, the graph below shows overall SAIFI (allowing for STPIS exclusions) for the last 5 years[95]. SAIFI is used here as this should be more reflective of the effect of the capital programs i.e. SAIDI will be partly reflective of changes to CAIDI, which we would expect to have stronger relationship to opex via Aurora's response/repair actions.

If we assume the overall impact of the historical capex on SAIFI can be gauged from the trend in SAIFI over the previous 5-year period (i.e. the trend approximates the *expected* SAIFI in that year) then the orange dashed line indicates the predicted SAIFI assuming a linear trend continues in the current period to the first year of the next. This linear trend

[95] This has been developed based upon the outage data and exclusions used by the AER for its STPIS assessment.

suggests around a 6% per annum improvement in SAIFI. The prediction based upon this trend is significantly lower than that from the simple 5-year average. Moreover, the prediction based upon the trend is also significantly lower than the AER SAIFI target, which makes some small adjustments from the 5-year average to account for the TRIP programs. This analysis suggests that other capital programs have probably had a significant impact in improving reliability over the current period.

**Figure 2 Historical SAIFI and effect of non-demand capex**




Based upon the above, we are not convinced that Aurora requires a provision in its capex allowance associated with these local reliability programs. Consequently, we do not consider that the position in our original report needs to be changed.

### 3.3.2 Remote control and protection

***Nuttall Consulting original review***

Aurora's original proposal classified seven capex programs as part of its remote control and protection programs[96]. This allowed for approximately $9.0 million over the next period. We considered all these programs were associated with improving reliability and/or associated cost reductions. As such, we believed that a specific provision for these programs in the capex allowance was not required.

***Aurora revised proposal***

Aurora's revised proposal has accepted our view for five of these programs. However, Aurora considers there should be a provision for the other two[97]. Its view here is that these two programs are required to ensure compliance with NER obligations.

Specifically, Aurora considered that these two programs were required to comply with NER S5.1a.8, which relates to maximum fault clearance times that protection must be able to operate to protect assets[98].

Both programs were planned to address existing protection arrangements in locations that Aurora considered were not compliant with these NER obligations. Aurora considered

[96] See discussion in our original report, pg 125
[97] AE125, pg 4
[98] Ibid

that the consequence of this was that assets in these locations could be damaged, due to the high fault levels that could eventuate under fault conditions due to incorrect fusing[99].

The revised proposal also noted that one program, associated with heavily loaded feeder spurs, also addressed operational and safety risks associated with such damaged assets[100].

***Discussion***

To better appreciate the difference between these programs and the other protection programs we did not allow for and Aurora accepted, we requested further information on these two programs[101], covering:

- references to where these two programs were discussed in previously provided asset management documentation
- information on the historical and forecast levels of non-compliance, and explanation of its forecasting methodology and assumptions.

We have reviewed the material referenced by Aurora and provided in response to our request. Summary points of these two programs are as follows[102]:

- **PRIGF** – This program is to alter/enhance existing protection in locations not considered by Aurora to be compliant, due to previous growth and changes to network. The need for such work is stated to be related to issues, such as inappropriate protection grading, which can result in the lack of protection of some assets and protection malfunctions[103].

  Following a review of distribution protection systems in 2009, 30 sites have been identified that require action. Work under this program involves different actions to address the issues at identified locations, such as the relocation of fuses, installation of ABS, and removal of extraneous fuses.

- **PRLVR** - This program is to alter/enhance existing protection on heavily loaded spurs (i.e. where loading has previously risen to a level that existing fuse-based protection may lead to issues with protection coordination and grading, and load switching.

  5 sites per annum have been addressed in the current period. Aurora has identified a further 26 sites it considers are still non-compliant. These are planned to be addressed in the next period. Works under this program typically involve the replacement of existing fuses with a recloser.

With regard to the non-compliance issue, the relevant NER provisions (NER S5.1a.8) concern the maximum time for protection systems to clear faults (e.g. a short circuit) on the network. S5.1a.8 (a)(3) requires that faults should be cleared sufficiently rapidly that "consequential equipment damage is minimised". For distribution voltages relevant to

[99] Ibid
[100] Ibid
[101] AER064, Question 1
[102] Ibid and attached documents
[103] Section 7.2, Protection and Control Management Plan

Aurora, a maximum time is not prescribed; the fault clearance time for distribution voltages applicable to Aurora (Table S5.1a.2) is defined "as necessary to prevent plant damage...". Moreover, for *facilities* constructed before the *performance standard commencement date* (for Aurora this would be when it joined the NEM), the applicable clearance times should be derived from the capability on the commencement date.

Based upon our understanding of these obligations, we do not consider this to be a strict compliance obligation as, based upon Aurora's explanation of these programs, we assume they all relate to assets constructed prior to it joining the NEM.

As such, in these circumstances, we consider that Aurora would need to demonstrate good engineering grounds that these programs are required (e.g. significant risks associated with safety or damage to other parties assets). Such a demonstration would need to clearly define these risks faced by Aurora. Furthermore, Aurora would need to demonstrate that the other benefits we had assumed are largely immaterial, and as such, there are no additional benefits in undertaking the programs.

In both cases, we do not consider that the information provided by Aurora adequately makes these cases.

For example, we do not believe that Aurora, although requested, has provided any substantial evidence that robustly quantifies the risks faced by Aurora due to these existing issues. It is acknowledged that Aurora has developed bottom-up estimates of the specific locations where existing protection may not meet internal criteria, and the work required to address these. We have no reason to doubt this analysis. Nonetheless, the information only makes claims of the possible consequences of such situations. It has not attempted to quantify risks, in an economic sense.

While we accept that these consequences may occur under particular circumstances, we do not consider that Aurora has adequately demonstrated that the actual risks faced by Aurora are material. For example, Aurora has not provided any case studies of actual locations that attempt to quantify specific issues and risks (probabilities and consequence) associated with these issues and options to alleviate these risks. Furthermore, Aurora has not provided historical data to show actual past events due to these existing issues; such historical data would help support the proposition that existing risks are material and the benefits we have assumed are not.

In the absence of information to support the contrary, we still consider that if these risks are material then we would expect that both the existing cost base of Aurora and network performance would reflect these risks and their prudent management. As such, we still maintain that in our view the prudent and efficient capex for these programs would be largely justified via the benefits we have assumed, including:

- reductions in costs associated with restoration via the improved protection
- reduction in costs associated with repairs, due to less damage to assets
- reductions in costs associated with investigating protection mal-operations, or damage to Aurora's or other parties assets

- improvements in customer supply reliability through the improved protection (e.g. fewer long outages due to failed assets, increased opportunities for shorter outages via remote control, fewer customers being affected by an outage through smaller outage sections)
- reductions in capitalised fault-related asset replacements, due to the improved protection of assets.

Based upon the above, although we accept that these programs may well be required in some form, we do not consider that a provision is required in the capex allowance for these two programs. Consequently, we do not consider that the position in our original report needs to be changed.

### 3.3.3 Other programs

***Nuttall Consulting original review***

In our original review we classified four of Aurora's capex programs within our reliability category. This allowed for approximately $6.7 million over the next period.

We did not consider a provision was required through the capex allowance for these programs as we believed that they all related to works that would be justified through future expenditure savings and reliability improvements. Implicit in this view was that these programs were not driven by mandatory obligations.

The programs, drivers and benefits, as we saw them, were as follows[104]:

- RELSA was a program to fit lightning arrestors to protect existing assets from the lightning strikes. Unprotected assets can be damaged or destroyed by lightning strikes. As such, we saw the benefits of this program to be largely related to the anticipated reduced occurrence of such damage and associated outages, including operating savings (e.g. reduced restoration and repair costs), reliability improvement through less outages, and potentially capex saving as they should be less assets being replaced due to failure.
- REILA was a program to rectify sites where existing protection does not adequately protect LV circuits. We saw the benefits here being similar to those noted above.
- REINC, as defined in Aurora documentation, was a program to protect assets from damage due to wildlife (e.g. the installation of possum guards). We saw the benefits here being similar to those noted above.
- REOTC was a program to create or repair access tracks to its assets. We saw the benefits of this program being more efficient operating and maintenance costs and reduced outage times (i.e. improved reliability), as access to assets should be improved.

[104] Our assumed benefits for each program were not explicitly discussed in our original report; however they were implied through the overall discussion.

We do acknowledge that safety risks were raised in Aurora's support documents for some of these programs. However, for the reasons discussed further below, we believed that the benefits noted above would allow for any reduction in such risks.

***Aurora position***

Aurora's position in its revised proposal is that none of these programs are primarily related to addressing reliability, and as such, there should be provision in the capex allowance for these programs.

Aurora provided further supporting documents for these programs, which stated the following important matters[105]:

- The access track program (REOTC) was driven by safety matters. It stated that the program was to address situations where the condition of an access track is so poor that it cannot be safely used without major repairs (e.g. building river crossings) or a new access track needs to be created. It also noted that funding had not been allowed by OTTER in an earlier distribution decision, and as such, a number of access tracks were lost due to erosion and overgrown vegetation. Finally, it considered that building these access tracks would not reduce opex and would have minimal impact on GSL payments.
- The fuse reach program (RELSA) was driven by safety matters. It noted that the primary consequences of the lack of protection was related to faults that would not be cleared from the system, resulting in asset damage (e.g. live conductors falling to the ground) that could start a bushfire or pose a public safety risk.
- The lightning arrestor program (REILA) was driven by the need to protect high-value assets from damage due to lightning strikes on its network - with additional reliability outcomes.
- The program we understood was to protect assets from wildlife[106] (REINC) was, in fact, intended to protect wildlife from its assets. Aurora stated that this program was similar to another program we had allowed for (SIWES). The only difference between the programs was that works under SIWES were at the request of government agencies and works under REINC were at the request of non-government parties. This program was therefore necessary to discharge Aurora's environmental management obligations. Aurora considered that it would be faced with legal risks if it did not undertake works associated with this program.

***Discussion***

Firstly, as a general comment on Aurora's view that we considered that the primary driver for undertaking these works was to address reliability. We consider that this misrepresents our view at that time. As noted above, we did not consider that there was any clear mandatory obligations associated with undertaking works associated with these

[105] AE118 (REOTC), AE119 (RELSA), AE120 (REILA), AE124 (REINC)

[106] An example of this would be wildlife causing short circuits (via electrocution of the wildlife), which may damage assets and lead to outages.

programs. As such, we believed that the prudent and efficient level of investment would be justified via the expenditure savings and/or reliability improvements. This has to also be seen in the context of our position discussed above, with regard to local reliability programs, in that our provision for capex associated with our replacement category should be sufficient to maintain performance. As such, the capex associated with programs may well be needed; however, they would be funded through other revenue mechanisms.

The main matter for our consideration here appears to be whether the other issues driving the need for these programs raised by Aurora in its revised proposal would be sufficient to justify a provision in the capex allowance in additional to that from alternative funding via the benefits we assumed.

As noted above, the drivers raised by Aurora are:

- safety risks for the access track and fuse reach programs
- protection of assets for the lightning arrestor program
- protection of wildlife, at the request of a non-government external party, for the remaining program.

Given the nature of these programs, with regard to the access track, fuse reach and lightning arrestor programs, we do not dispute that they will address these issues raised by Aurora. This position is not dissimilar to information Aurora provided on these programs in support of its original proposal.

With regard to the program to protect wildlife, we consider that Aurora's revised proposal significantly contradicts the information provided to support this program in its original program. As such, capex requirements for this program will be discussed separately below.

*Access tracks, fuse reach and lightning arrestors*

With regard to the safety issue, in our original review we considered that the benefits of these programs, noted above, would outweigh the stated safety concerns, and as such, these benefits would be sufficient on their own to justify incurring capex. In coming to this view, we considered that the safety risks were known during the last period[107], and as such, Aurora had either accepted these or was incurring costs associated with the prudent management of these i.e. we had no evidence to say that Aurora was inappropriately accepting these safety risks.

For example, with the access track program, if these tracks are significantly degraded or even non-existent, resulting in serious safety concerns, then we would expect that to mitigate these safety risks there would be both:

- increased management costs associated with assessing the specific safety risks of particular tracks and instructing field staff on appropriate techniques in these circumstances

[107] This is different from some of the increases in the replacement category that we allowed for, where Aurora indicated that the scale of the safety risk had only been realised recently through audits.

- increased field costs associated with travel and possible vehicle requirements and/or crew sizes.

Without evidence to the contrary, we would have to assume that these actions and associated costs are resulting in safety risks being reduced to appropriate levels. As such, the program is still justified based upon future cost savings over the existing cost base (and reliability improvements if material).

In the case of the asset protection driver for the lightning arrestor program, we considered that this program must be effectively self-funding through future opex and capital reductions and improvements on reliability. If this was not the case, then without any other driver, it would seem that the efficient solution would be to continue with unprotected assets and incur the existing costs should a failure due to a lightning strike occur. In this regard, Aurora has advised that this program is not driven by any mandatory compliance obligations[108].

The appropriateness of the above two positions has to be seen in the context of the capex and opex allowances, which were largely assessed based upon forward-trending of historical costs.

The Aurora revised proposal does not provide any new evidence to justify that these positions are no longer valid. Therefore, we have requested further information from Aurora on the level of risks in the current and next period associated with these other drivers[109]. We have also requested information on the management of these risks in the current period and how and why this is set to change in the next[110].

Aurora's response on these matters provides little new information that has not already been provided. With regard to the level of safety risk associated with the fuse reach and access track programs, the response simply reaffirms that a risk assessment was undertaken and found the risk rating to be "high"[111]. The response does not provide any useful additional information on the quantification of these risks and the management of the safety risks in the current period.

With regard to the safety risks associated with the access track programs, we still consider that either these risks must not be as high as suggested by Aurora, or if they are, then costs must be being presently incurred to prudently manage these risks. Similarly, in the case of installing lightning arrestors, Aurora has not presented any compelling evidence to refute our position given above.

Therefore, for these two programs, although we accept that these programs may well be required in some form, we do not consider that a provision is required in the capex allowance for them.

With regard to the fuse reach program, we still maintain that there should be some benefits of the form we previously considered. However, in the case of this program, we

[108] AER064, pg 6
[109] AE064, Question 3(c)
[110] AE064, Question 3(d)(ii)
[111] AE064, pg 7 and pg 8

accept that it may be more difficult to manage the safety risks and it is these risks that are primarily driving the need for the program. As such, unlike the access track program, there may not be significant costs associated with managing these safety risks in the current cost base. We also note that the program is prioritised for fire danger areas, where safety risks could be very high[112].

Consequently, we accept that a provision in the capex allowance associated with this program is required to maintain the safety of the distribution network. Furthermore, the volume and costs proposed by Aurora do not appear unreasonable to us. This represents a change to our position in our original report.

*REINC – related to the protection of assets or wildlife*

As noted above, we consider that Aurora's revised proposal contradicts the stated drivers and benefits of this program, as provided in its supporting documentation associated with its original proposal[113]. This document states that the "*aim of this program is to reduce the risk to the assets posed by interactions with wildlife*"[114]. In providing background on this program, the document discusses wildlife contact in terms of the impact on assets and supply, not the fatality of the wildlife[115]. The quantification of the issues is then given based upon the number of recorded outages due to wildlife in 2010/2011 – note, not the number of fatalities of wildlife or requests from external non-government parties[116]. It then goes on to state that this is a "reactive program to **protect equipment from damage due to wildlife contact**"[117] (emphasis added) – note, not to protect wildlife from injury due to the assets. Finally, it states that the benefits of the program are "avoided asset replacement"[118].

Nowhere in this document does it provide what would now appear to be the most important information associated with the need for this program, namely:

- that its primary intention is to protect wildlife from its assets
- that work under this program is a consequence of specific requests from external, non-government parties.

Given these significant differences between the revised proposal and the previous documentation provided by Aurora, we requested that Aurora provide some discussion that resolves the apparent contradiction.

In response to this Aurora stated:

> "*Aurora does not consider that the REINC program is a reliability program and questions Nuttall Consulting's classification of this program as being reliability*

112 AE064, pg 8
113 NW-#30205224-v2-Justification_REINC_Install_Insultation_Covers.pdf (confidential), provided in the Aurora email dated 12/8/2011
114 Ibid, S1, pg 1
115 Ibid, S2, pg 1
116 Ibid, S3, pg 1
117 Ibid, S7, pg 2
118 Ibid, S5, pg 1

> *related. Aurora has previously argued this position and has continuously classified these programs as Regulatory Obligations or Requirements. These programs specifically mitigate issues associated with the potential fatal outcomes of the interactions between fauna and Aurora's assets, and the potential asset consequences arising from those interactions."*[119]

We consider that this response does not adequately answer our question, and provides no further information to resolve our view of the contradiction of Aurora's revised proposal with its previous documentation. As such, we have no basis to change our original position.

We note that Aurora has raised the issue of legal risks associated with its new driver. We understand however that the AER will consider this matter, and consequently, we have not considered this program further.

[119] AER-064, pg 6

# 4 Opex – step change for IT investment

Aurora has proposed step changes in operating expenditure of $11.8 million[120] associated with its information technology (IT) systems. For the purposes of this review a step change means an incremental increase or decrease in costs that is incurred from:

- new, changed or ceased regulatory obligations or requirements,
- changes in operating environment
- where the Base Year allowance is not sufficient to meet forecast operating expenditure.

Aurora has identified that the increased opex is due to the move to a new generation platform for its information system. In its draft determination[121] the AER approved a major information technology capex program as proposed by Aurora. The Aurora Distribution Network IT Strategy[122] describes a 10 year program focussed on technology consolidation and simplification, as well as enhancing strategic capabilities. The proposed opex step change investment represents Aurora's estimate of the increased operating expenditures associated with this strategy.

The following table provides the proposed additional opex for the next control period[123].

**Table 2 IT step change proposal**

| | Total opex ($ millions) | | | | | |
|---|---|---|---|---|---|---|
| | 2012 - 2013 | 2013 - 2014 | 2014 - 2015 | 2015 - 2016 | 2016 - 2017 | Total |
| **Total opex** | 1.47 | 1.47 | 2.70 | 2.86 | 3.34 | 11.85 |

We understand that this opex step change was not identified by Aurora in its original proposal[124]. Consequently, the AER did not specifically assess this for its draft determination or request us to review this step change – although, our original report included the detailed review of the IT capex project.

The information contained in this review has been provided as part of the Aurora revised proposal and a subsequent information request process.

[120] All expenditures in this section of the report are provided in $2009/10
[121] Draft Distribution DeterminationAurora Energy Pty Ltd, 2012–13 to 2016–17, AER, November 2011
[122] Aurora Energy Distribution Network IT Strategy 2012-2017, Final Version 1 Aurora Energy, 15 March 2011 (confidential)
[123] IT step change analysis Final Revision.xlsx (confidential)
[124] Aurora Energy Revised Regulatory Proposal 2012–2017, Aurora Energy, p63

## 4.1 Overview

The AER regulatory information notice[125] defines a step change to mean an incremental increase or decrease in costs incurred primarily arising from:

- new, changed or ceased regulatory obligations or requirements
- changes in operating environment
- where the Base Year allowance is not sufficient to meet forecast operating expenditure.

With note to the definition for a step change discussed in the introduction to this section, the proposed opex step change appears not to be based on changes to obligations, regulations or the operating environment. Aurora has described the step change as relating to the strategic intent to consolidate and simplify the IT operating environment. This is a response to the current internal complexity of Aurora's IT systems and therefore not a result of any external changes to regulations or the operating environment.

As such, we have assessed the step change on the basis that it is required because the base year allowance is insufficient. This premise will be considered in more detail in the detailed review of the expenditures later in this section.

Aurora has identified a number of discrete projects within the IT opex step change. The information provided by Aurora included a number of IT items of which expenditure is already being incurred. Where expenditure is already being incurred and is forecast to continue being incurred at a similar level, we have not considered the item as a step change. The following table lists the existing fees, licences and agreements that fall into this category.

**Table 3 Ongoing licences, fees and agreements[126]**

| Description |
|---|
| Logica Investigation Charges |
| Logica Discretionary Charges |
| GPATS weather subscribtion(sic) |
| Licence Renewal fro (sic)Itron Software MV-RS & FC200 |
| Licence Renewal for Itron Software MV-90xi |
| Software MVRS - Handheld software |
| 2 year maintenance renewal - Bently applications |
| Tas current observations - lightning data Maintenance of feed |
| DINIS Core 2nd License Annual Support and Maint. |
| DINS Software annual maint.& support |
| DINIS API/SDK Module Annual Support |
| Intergraph Quarterly Maintenance |
| Quarterly Maintenance on additional InService |

[125] Aurora – RIN Template, Definitions worksheet
[126] IT step change analysis Final Revision.xlsx (confidential)

| Description |
|---|
| In ServiceCAD SLA extension |
| INTERGRAPH MAINTENANCE CHARGES |
| iFix Global software support agreement |
| Intellution SCADA GlobalCare Renewal |
| Supscription (sic)rnwl - Designer Ent. Edition x2 |
| 1yr tech support &maint - LabelWeb Pro &GeoLabel |
| Office Equipment Consumables, Repairs & Maintenance |
| Server Consumables, Repairs & Maintenance |
| Data Services for Mobile Computing |
| Weather Data - Weatherzone |
| Miscellaneous Data |

We have only assessed the IT items that Aurora has identified as new or increased from current expenditures. The following table provides a breakdown of the opex Aurora has forecast for these items[127].

**Table 4 IT step change breakdown**

| | Total opex ($000) | | | | | |
|---|---|---|---|---|---|---|
| | 2012 - 2013 | 2013 - 2014 | 2014 - 2015 | 2015 - 2016 | 2016 - 2017 | Total |
| [redacted] | 159.3 | 159.3 | 159.3 | 159.3 | 159.3 | 796.3 |
| Backend systems | 190.0 | 190.0 | 190.0 | 190.0 | 190.0 | 950.0 |
| SMS Hub | - | - | 30.0 | 185.0 | 185.0 | 400.0 |
| Market Interfaces | 1,122.0 | 1,122.0 | 1,122.0 | 1,122.0 | 1,122.0 | 5,610.0 |
| DMS & SCADA | - | - | 960.9 | 960.9 | 960.9 | 2,882.8 |
| Customer Case Management | - | - | - | - | 484.0 | 484.0 |
| Tariff Modelling | - | - | 242.0 | 242.0 | 242.0 | 726.0 |
| **Total opex** | **1,471.3** | **1,471.3** | **2,704.2** | **2,859.2** | **3,343.2** | **11,849.0** |

In general, the opex forecasts associated with each item are high-level and sourced from Aurora Network's IT strategy[128].

The following section provides an overview of the IT strategy. In the subsequent sections of this chapter we discuss our review of each of these items.

## 4.2 Information Technology strategy

As described in Nuttall Consulting's report on Aurora's proposed capex and alternative control services for the AER's draft determination, Aurora is proposing a fundamental change to the structure of its IT systems. The Aurora IT strategy has not changed since our previous report.

[127] IT step change analysis Final Revision.xlsx, Aurora Energy via email 29 February 2012. (confidential)

[128] NW-#30110423-v1D-Network_IT_Strategy_2010.DOC and Aurora Distribution Network ISG Strategy 2012 - 2017.docx (confidential)

The aim of this strategy is to enable and support Aurora's aspirational goal for its distribution business of achieving "the strategic metrics of 16% operational cost reduction through increasing operational efficiency and $20 million capital expenditure reduction over the 2012-2017 RCP"[129].

The current architecture could be characterised as being comprised of a large number of relatively discrete systems. The proposed future architecture is based on a more unified and integrated platform. This is referred to as a Tier 1 solution where a single technology platform provides that base structure for the business's IT systems.

As one of the smallest electrical distribution businesses in Australia, Aurora has previously considered that it did not have the scale of operations to move to a Tier 1 solution. A number of recent consultancy reviews[130] undertaken for Aurora have challenged this position and identified potential benefits in moving to a Tier 1 solution. This approach was selected by Aurora's executive steering committee as the preferred option[131].

Enterprise Architects was engaged to develop a strategic architecture and roadmap for Aurora's distribution business. The output of this engagement provided an input to Aurora's pricing determination submission for the next control period.

The technology roadmap and supporting documentation are the key documents we have relied on in undertaking our review of the step change in opex associated with this IT strategy.

We note that the forecast opex is based on the assumption of moving to a Tier 1 solution. At the time of writing this report, Aurora has advised that no Tier 1 provider has been selected or business commitment yet made to confirm that this approach will actually be adopted[132].

Our assessment of the step change in opex is made on the basis that the "16% operational cost reduction … and $20 million capital expenditure reduction" are incorporated in the base opex and capex forecasts. We would not recommend any portion of the proposed opex step change amounts in the absence of these overall expenditure reductions.

## 4.3 [redacted]

Aurora is proposing step change expenditure of $796,300 associated with the implementation of a network modelling and simulation tool. Aurora is proposing to replace the current network modelling and analysis tool it uses, known as DINIS, with an alternative called [redacted] Both DINIS and [redacted] are commercially available applications developed for these purposes. DINIS is owned by Fujitsu, while [redacted] is a product of [redacted]

[129] NW-#30110423-v1D-Network_IT_Strategy_2010.DOC (confidential)
[130] Marchment Hill IT Strategy review, and Enterprise Architects architectural analysis.
[131] Aurora Distribution Network ISG Strategy 2012 – 2017, p3 (confidential)
[132] Ibid, p12

Aurora has not provided a detailed capital expenditure forecast for the [redacted] implementation. An initial assessment of the DINIS replacement was made at $1m, although this was not supported with any analysis[133].

The following table describes the forecast opex step change associated with the [redacted] product.

**Table [redacted] step change proposed opex**

| | Total opex ($000) | | | | | |
|---|---|---|---|---|---|---|
| | 2012 - 2013 | 2013 - 2014 | 2014 - 2015 | 2015 - 2016 | 2016 - 2017 | Total |
| **Proposed opex** | 159.3 | 159.3 | 159.3 | 159.3 | 159.3 | **796.3** |

Network modelling and simulation is a core activity for a distribution network business. Consequently, a DNSP requires applications of this type to meet its obligations and manage and plan its network in a safe and efficient manner.

The information provided by Aurora relating to the IT strategy is consistent in identifying the retirement/replacement of the DINIS software with the [redacted] product. This documentation identifies that the DINIS product is not consistent with the Aurora IT strategy[134] and that an alternate solution is recommended. [redacted] is identified as one option for the replacement of DINIS.

The current operating expenditures of the DINIS software are reported by Aurora at $43,000 per annum. This includes:

- DINIS Core 2nd license annual support and maintenance
- DINS Software annual maintenance and support
- DINIS API/SDK module annual support.

These costs will not be required after the DINIS product is retired - although there would most likely be a transitional/overlap period where both products would be operational. On this basis, we recommend reducing the proposed opex step change for the [redacted] product by $43,000 per annum with the exception of the first year of the regulatory control period.

Based upon the above, the following table provides our recommended step change expenditures associated with the change to the [redacted] software.

**Table [redacted] step change recommended opex**

| | Total opex ($000) | | | | | |
|---|---|---|---|---|---|---|
| | 2012 - 2013 | 2013 - 2014 | 2014 - 2015 | 2015 - 2016 | 2016 - 2017 | Total |
| **Recommended opex** | 159.3 | 116.3 | 116.3 | 116.3 | 116.3 | **624.3** |

[133] Application Assessment Data - Distribution 20101102.xlsx (confidential)
[134] Application Assessment Data - Distribution 20101102.xlsx (confidential)

## 4.4 SMS Hub

Aurora is proposing a step change in expenditure of $400,000 associated with new IT system functionality for the purposes of distribution customer messaging. This functionality is to provide Aurora with an SMS communications tool, known as an SMS hub. Aurora currently does not provide a service to allow customers to opt in for notification by electronic means, primarily being SMS or email for activities that effect the customer. Aurora has provided examples[135] of where customers could benefit from information that is not currently provided, including:

- the successful commencement and completion of reading the meter where a customer is required to restrain an animal
- the cancellation of a planned outage
- the completion of a service order request
- accessing a customer's property for the purposes of inspecting Aurora's infrastructure.

Total capex proposed for this system is $1.29 million[136]. The following table describes the forecast opex step change associated with the SMS hub.

**Table 7 SMS hub step change proposed opex**

| | Total opex ($000) | | | | | |
|---|---|---|---|---|---|---|
| | 2012 - 2013 | 2013 - 2014 | 2014 - 2015 | 2015 - 2016 | 2016 - 2017 | Total |
| **Proposed opex** | 0.0 | 0.0 | 30.0 | 185.0 | 185.0 | 400.0 |

The information provided by Aurora[137] relating to the SMS hub describes the creation of a 'Distribution Customer Messaging Hub', which consisted of three elements:

- a web based subscription service for customers (integrated into the existing Aurora website)
- integrated communications
- real time and post event reporting capabilities.

We consider that Aurora has identified some potential benefits (refer above) associated with the proposed SMS hub, but has not reasonably shown that the benefits outweigh the proposed costs. Aurora has not provided any financial assessment of the value of the

[135] NW-#30111203-v1-SMS_Hub_Brief.DOC (confidential)
[136] NW-#30112516-v2-Asset_Management_Capability_Cost_Methodologi.XLS (confidential)
[137] NW-#30132696-v1-[redacted]_Discussion_Document_for_Outward_Facing_SMS_Capability.pdf, (confidential) NW-#30126582-v1-[redacted]-_Overview_Presentation_-_for_JS.pdf, and (confidential) NW-#30126583-v1-[redacted]_Overview_2010.pdf. (confidential)

customer benefits, or provided survey information to demonstrate that consumers would place a reasonable value on the proposed services.

We are not aware of any NEM DNSP that has implemented an SMS hub of the sort described by Aurora, although SMS hubs are used by some DNSPs for outage notification[138]. In addition, we consider that the proposed SMS hub is supplementary to the current system functionality and is not necessitated by the move to a Tier 1 solution.

Therefore, we do not consider that the SMS hub capability has been demonstrated to be prudent and efficient, and consequently, do not consider that any step change opex should be allowed for this IT item.

Following the above review, Aurora provided an additional report that contained qualitative support for the SMS hub. Whilst we consider that the SMS hub may provide some customer and network benefits, the report does not offer any additional information to change our original finding. We consider that there are no obligations on Aurora to implement the SMS hub, and that the implementation of this system could not at this time be considered standard industry practice. If the SMS hub reduces current expenditures, then Aurora is incentivised to pursue these under the current regulatory framework.

## 4.5 Backend systems

Aurora is proposing step change expenditure of $950,000 for backend systems associated with the Tier 1 rollout. Aurora has advised that these expenditures relate to licence fees for a software package that supports the collection, storage, display and reporting of time series data, known as Historian[139]. The associated capex for this program is $1.7 million[140].

The following table describes the forecast opex step change associated with the proposed backend systems.

**Table 8 Backend systems step change proposed opex**

| | Total opex ($000) | | | | | |
|---|---|---|---|---|---|---|
| | 2012 - 2013 | 2013 - 2014 | 2014 - 2015 | 2015 - 2016 | 2016 - 2017 | Total |
| **Proposed opex** | 190.0 | 190.0 | 190.0 | 190.0 | 190.0 | 950.0 |

Aurora has advised that the Historian software is an active project and is currently planned to be fully implemented this financial year. The introduction of this system is consistent with the Tier 1 approach proposed by Aurora and with the development of a smart grid network.

Aurora has provided the following breakdown of the Historian annual operating expenditures.

[138] E.g. Powercor Australia Ltd
[139] Technology Roadmap Initiative Briefs.pptx (confidential)
[140] Historian Cost Build up.xls (confidential)

**Table 9 Historian opex breakdown**[141]

| | $opex |
|---|---|
| Licence Fees Yrs 2 - 5 | 143,100 |
| System Administrator | 26,600 |
| Logica Support Costs | 16,800 |
| Escrow | 2,200 |
| **Total OPEX P/A** | **188,700** |

The primary cost in the build-up is the annual license fees. Aurora has provided source information from the software vendor's agent in Australia that verifies the licence fees to be US$132,500 per annum. The Aurora cost build-up applied an additional 8% multiplier to the licence fee[142]. We have assumed that this is intended to represent the exchange rate adjustment and should be an 8% reduction based on the current exchange rate. Aurora has confirmed that this is correct[143].

We have considered the system administrator costs and Logica support costs and accept the proposed amounts. These amounts are consistent with the scale of the project and reasonably required to support the proposed program.

Aurora has not provided information to support the escrow amount of $2,200 per annum. A typical IT escrow arrangement is to ensure that the purchaser is able to access and use the source code and other relevant materials to allow them, on the occurrence of certain events, to obtain ongoing support for software with as little disruption as possible. We have not removed this item as the proposed escrow services appear reasonable for the type of system proposed.

The following table provides our recommended step change expenditures associated with backend systems.

**Table 10 Backend system step change recommended opex**

| | Total opex ($000) | | | | | |
|---|---|---|---|---|---|---|
| | 2012 - 2013 | 2013 - 2014 | 2014 - 2015 | 2015 - 2016 | 2016 - 2017 | Total |
| **Recommended opex** | 168.3 | 168.3 | 168.3 | 168.3 | 168.3 | 841.4 |

## 4.6 Market Interfaces

Aurora is proposing step change expenditure of $5,610,000 for market interfaces associated with the Tier 1 rollout. This program of works is referred to by the group name

141 Historian Cost Build up.xls (confidential)
142 Ibid
143 John Sayers email dated – 20/3/2012

of DSN.01 in the Aurora technology roadmap documentation  The Market Interfaces program is intended to support upgrades to existing national electricity market communications whilst implementing additional functionality.

The proposed upgrades include, but are not limited to, general enhancements to support additional reporting functionality, upgrades for increases in data volumes and a general platform migration. The capex associated with this program is forecast at $5.1m[144].

The following table describes the forecast opex step change associated with the proposed market interfaces.

**Table 11 Market interfaces step change proposed opex**

| | Total opex ($000) | | | | | |
|---|---|---|---|---|---|---|
| | 2012 - 2013 | 2013 - 2014 | 2014 - 2015 | 2015 - 2016 | 2016 - 2017 | Total |
| **Proposed opex** | 1122.0 | 1122.0 | 1122.0 | 1122.0 | 1122.0 | 5610.0 |

We understand that the DSN.01 Market Interfaces category includes the extension of Bravo Systems and the maintenance of Gentrack to enhance the way Aurora's systems communicate and also improve internal reporting. The step change information provided by Aurora assumes that 22% of the projected capex will be incurred as step change opex. This assumption is referenced to the Aurora Technology Roadmap cost model[145] and is consistent with industry average rates of (17% to 22%) for software/licence fees.

The DSN.01 category is consistently referenced within the Aurora documents and represents a core component of the Aurora IT strategy.  Noting the Nuttall Consulting recommendation in our original report to accept the capex associated with the IT capital program for the next control period, we consider that any associated step change opex should also be considered.

In reviewing the proposed market interface expenditure we note that the forecast capex for the Gentrack and Bravo systems is based on internal, and to a lesser extent external, resourcing. This means that the program development is being undertaken with internal labour[146], and not through the purchase of external software. As such, there are no additional software costs associated with these activities. In the absence of these software purchase costs, it is not reasonable to apply a software licencing cost as there is no software to licence.

This position is supported by the Aurora Technology Roadmap cost model[147], which identifies only internal and external resource costs and no software licence costs. In addition, this model specifically identifies no costs (i.e. a zero value) associated with support costs for the DSN.01 initiative in the first year. The cost model clearly identifies other support costs for initiatives that have associated software costs.

[144] IT step change analysis Final Revision.xlsx (confidential)
[145] Technology Roadmap Cost Model v4.0.xlsx (confidential)
[146] And a smaller amount of external labour
[147] Technology Roadmap Cost Model v4.0.xlsx (confidential)

Therefore, we do not consider that any step change opex should be allowed for this IT item.

## 4.7 DMS & SCADA

Aurora is proposing step change expenditure of $2,882,800 for Distribution Management Systems (DMS) and Systems Control and Data Acquisition (SCADA) upgrades associated with the Tier 1 rollout. This program of works is referred to by the group name of DSN.05 in the Aurora technology roadmap documentation.

The capex associated with this project is forecast at $10.4 million[148].

The following table describes the forecast opex step change associated with the proposed DMS and SCADA upgrades.

**Table 12 DMS and SCADA step change proposed opex**

| | Total opex ($000) | | | | | |
|---|---|---|---|---|---|---|
| | 2012 - 2013 | 2013 - 2014 | 2014 - 2015 | 2015 - 2016 | 2016 - 2017 | Total |
| **Proposed opex** | 0.0 | 0.0 | 960.9 | 960.9 | 960.9 | 2882.8 |

The annual expenditure value of $960,920 is based on a quotation[149] from [redacted] and includes an indicative discount. The costing approach proposed by Aurora for the DMS and SCADA initiative is to adopt the [redacted] system. The [redacted] system is an integrated network management solution that automates many aspects of the real-time management, monitoring and control of an electrical distribution network.

The proposed approach includes a number of [redacted] applications (15 in total)[150]. These applications are proposed to replace or modify a number of existing Aurora applications, including:

- WSOS
- SCADA
- SwopCheck
- Network Load Shedding Tool
- Distribution Loss Factors
- NULEC
- Logsheet
- FLRS

[148] NW-#30112516-v2-Asset_Management_Capability_Cost_Methodologi.XLS (confidential)
[149] Cover letter ik14072010.pdf (confidential)
[150] Ibid

- DINIS[151]
- GNetViewer.

Aurora estimates that the DSN.05 initiative will span 18 months. The initiative is currently scheduled to commence at the start of 2015 with a target completion date mid 2016.

The proposed project commencement date aligns with the initial licence fee amounts. It is not clear from the Aurora documentation as to the timing of the initial invoice from [redacted] (e.g. at project commencement or upon operational handover). We accept that the initial fees could be incurred in the latter half of 2015 and have not made any adjustments on this basis.

We have reviewed the list of current licence fees provided by Aurora and, with the exception of DINIS, have not identified any additional licence fees that would be replaced by the DSN.05 initiative. The removal of the DINIS licence fees have already been accounted for in the [redacted] review (section 4.3).

On the basis of the above review, we consider that the proposed opex step change is reasonable.

## 4.8 Customer Case Management

Aurora is proposing step change expenditure of $484,000 for customer care management associated with the Tier 1 rollout. This program of works is referred to by the group name of DSN.06 in the Aurora technology roadmap documentation.

The capex forecast for this component of the IT initiative is $2.2 million.

The following table describes the forecast opex step change associated with the proposed customer care management.

**Table 13 Customer care management step change proposed opex**

| | Total opex ($000) | | | | | |
|---|---|---|---|---|---|---|
| | 2012 - 2013 | 2013 - 2014 | 2014 - 2015 | 2015 - 2016 | 2016 - 2017 | Total |
| **Proposed opex** | - | - | - | - | 484.0 | 484.0 |

Aurora has advised[152] that the DSN.06 Customer care management category allows for the extension of Aurora's customer care and billing system, implemented in [redacted]

As with the marketing interfaces item discussed above, the step change information provided by Aurora assumes that 22% of the projected capex will be incurred as step change opex. This assumption is referenced to the Aurora Technology Roadmap cost

[151] Partial replacement and interface modifications.
[152] Technology Roadmap Initiative Briefs.pptx (confidential)

model[153] and is consistent with industry average rates of (17% to 22%) for software/licence fees.

The DSN.06 category is consistently referenced within the Aurora documents and represents a core component of the Aurora IT strategy. Noting the Nuttall Consulting recommendation to already accept the capex associated with the IT capital program for the next control period, we consider that any associated step change opex should also be considered.

In reviewing the proposed customer case management expenditure we note that the forecast capex is based on internal, and to a lesser extent external, resourcing[154]. This means that the program development is being undertaken with internal labour , and not through the purchase of external software. As such, there are no additional software costs associated with these activities. In the absence of these software purchase costs, it is not reasonable to apply a software licencing cost as there is no software to licence. This position is supported by the Aurora Technology Roadmap cost model[155] which identifies only internal and external resource costs and no software licence costs. In addition, this model specifically identifies no costs (i.e. a zero value) associated with 1st year support costs for the DSN.06 initiative. The cost model clearly identifies other support costs for initiatives that have associated software costs.

Therefore, we do not consider that any step change opex should be allowed for this IT item.

## 4.9 Tariff Modelling

Aurora is proposing step change expenditure of $726,000 for tariff modelling associated with the Tier 1 rollout. This program of works is referred to by the group name of DSN.07 in the Aurora technology roadmap documentation. Tariff modelling is proposed to introduce two new technology capabilities into Aurora:

- a consumer profiling engine used to create half-hourly consumption data from profiles imported from AEMO
- a tariff modelling/forecasting solution to support what-if analysis of forecasted tariff scenarios.

The capex forecast for tariff modelling in the next period is $1.1 million[156].

The following table describes the forecast opex step change associated with the proposed tariff modelling.

[153]Technology Roadmap Cost Model v4.0.xlsx (confidential)
[154]Technology Roadmap Cost Model v4.0.xlsx (confidential)
[155]Technology Roadmap Cost Model v4.0.xlsx (confidential)
[156]IT step change analysis Final Revision.xlsx (confidential)

**Table 14 Tariff modelling step change proposed opex**

| | Total opex ($000) | | | | | |
|---|---|---|---|---|---|---|
| | 2012 - 2013 | 2013 - 2014 | 2014 - 2015 | 2015 - 2016 | 2016 - 2017 | Total |
| **Proposed opex** | - | - | 242.0 | 242.0 | 242.0 | 726.0 |

Similar to the customer care management expenditure discussed in the previous section (section 4.8), the tariff modelling step change information provided by Aurora assumes that 22% of the projected capex will be incurred as step change opex. This assumption is referenced to the Aurora Technology Roadmap cost model[157]and is consistent with industry average rates of (17% to 22%) for software/licence fees.

The DSN.07 category is consistently referenced within the Aurora documents and represents a core component of the Aurora IT strategy. Noting the Nuttall Consulting recommendation to already accept the capex associated with the IT capital program for the next control period, we consider that any associated step change opex should also be considered.

In reviewing the proposed tariff modelling expenditure we note that the forecast capex is based on internal, and to a lesser extent external, resourcing[158]. This means that the program development is being undertaken with internal labour , and not through the purchase of external software. As such, there are no additional software costs associated with these activities. In the absence of these software purchase costs, it is not reasonable to apply a software licencing cost as there is no software to licence.

This position is supported by the Aurora Technology Roadmap cost model[159] which identifies only internal and external resource costs and no software costs. In addition, this model specifically identifies no costs (i.e. a zero value) associated with 1st year support costs for the DSN.07 initiative. The cost model clearly identifies other support costs for initiatives that have associated software costs.

Therefore, we do not consider that any step change opex should be allowed for this IT item.

## 4.10 Summary

Aurora is proposing an additional step change in opex of $11,849,007 in the next period. These step changes are a result of Aurora's proposed move to a new generation information system platform.

Based on our review of the information provided by Aurora, we are recommending that a step change amount of $4,348,433 be allowed for the next period. This represents a reduction of $7,500,574 or 63% from the original amount proposed by Aurora.

[157]Technology Roadmap Cost Model v4.0.xlsx (confidential)
[158]Technology Roadmap Cost Model v4.0.xlsx (confidential)
[159]Technology Roadmap Cost Model v4.0.xlsx (confidential)

The following table provides a breakdown of the recommend IT step change opex.

**Table 15 IT step change recommendations**

| | Total opex ($000) | | | | | |
|---|---|---|---|---|---|---|
| | 2012 - 2013 | 2013 - 2014 | 2014 - 2015 | 2015 - 2016 | 2016 - 2017 | Total |
| [redacted] | 159.3 | 116.3 | 116.3 | 116.3 | 116.3 | 624.3 |
| SMS Hub | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Backend systems | 168.3 | 168.3 | 168.3 | 168.3 | 168.3 | 841.4 |
| Market Interfaces | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DMS & SCADA | 0.0 | 0.0 | 960.9 | 960.9 | 960.9 | 2882.8 |
| Customer Case Management | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Tariff Modelling | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total opex** | **327.5** | **284.5** | **1,245.5** | **1,245.5** | **1,245.5** | **4,348.4** |

The majority of recommended reductions are based on the removal of items that are not considered to represent real or likely future expenditures. These reductions are consistent with Aurora's own internal documentation.

Other less major reductions are based on recognition of future cost reductions from the removal or replacement of existing license fees and expenditures. In the case of the SMS Hub, we consider that this is a discretionary expenditure and not integral to existing operations or the proposed new information system platform.

# 5 Other matters

## 5.1 Nuttall Consulting reconciliation of original opex findings

### 5.1.1 Background

For the draft decision, the AER developed an opex "base-step-trend" model to assess Aurora's opex forecast. In this approach, the AER used 2009/10 as the base year. As part of this assessment, the AER requested that we review the opex associated with six opex categories. Our assessment was to inform the AER's deliberations on the efficient 2009/10 base-line. The six categories assessed were:

- Network Division Management Expenditure
  - Network management – direct expenditure
  - Network management – unallocated – subcontractor expenditure
  - GSL payments – direct expenditure
- Maintenance Expenditure
  - Emergency & unscheduled power system response & repair
  - Vegetation management
  - Other

The main output of this assessment was a base-line estimate that removed non-recurrent expenditure that had been incurred that year (2009/10). The AER used these base-line findings as inputs in its "base-step-trend" model.

We understand that Aurora has provided two models associated with its opex forecast for the next period.

1 One model is based upon the AER's "base-step-trend" opex model that the AER used for its draft decision[160]. As noted above, for the draft decision, the AER used 2009/10 as the base year for this model. The model in the revised proposal has been updated by Aurora to reflect 2010/11 as the base year.

2 The other model is Aurora's proposed program of works model[161]. This is a "bottom up" model that has been developed by Aurora using individual project and program cost estimates, associated with the specific work items that underpin Aurora's revised capex and opex forecasts. Line items in this model are given a one-to-one mapping to capex and opex categories defined in the AER's RIN.

[160] AE147
[161] AE145

The AER has requested that we assess whether Aurora has made adjustments to these two models that reflect our previous findings.

### 5.1.2 Review

Before discussing our review, it is important to note that the Aurora revised proposal states that:

> *"Aurora has also analysed the review undertaken by Nuttall Consulting, when reviewing the 2009-10 operating expenditure, and factored a number of these recommendations into its revised operating expenditure forecasts.*
>
> *Aurora has reviewed Nuttall Consulting's analysis and conclusions in relation to operating expenditure relating to:*
>
> - *GSL payments;*
> - *emergency and unscheduled power system response and repair; and*
> - *vegetation management.*
>
> *Aurora has updated its forecast operating expenditure in these areas to reflect the outcomes within Nuttall Consulting's report."*[162]

As such, at the outset, it would appear that only opex associated with these three categories should reconcile with our previous findings. The revised proposal does not suggest that it has used the findings for the other three categories. As we will discuss further below, our review appears to confirm this.

We have reviewed the two opex models noted above. The findings of this review are summarised in the table below.

**Table 16 Reconciliation of opex review to Aurora models**

| Opex category | 2009/10 base line $('000) | 2010/11 BST model | Program of works model (POW model) |
|---|---|---|---|
| **Network management – direct expenditure** | **$8,120** | **Unable to confirm**<br>See our discussion below on this issue. | **Unable to confirm**<br>POW model does not explicitly use network management cost categories as specific line items. |
| **Network management – unallocated – subcontractor expenditure** | **$193** | **Not consistent**<br>2010/11 base line has increased to $492 – the actual value for that year. | **Unable to confirm**<br>POW model does not explicitly use network management cost categories as specific line items. |
| **GSL payments – direct expenditure** | **$1,755** | **Consistent**<br>Model uses our original figure directly. | **Unable to confirm**<br>POW model does not explicitly use network management cost categories as |

[162] Aurora revised proposal, pg 64

| Opex category | 2009/10 base line $('000) | 2010/11 BST model | Program of works model (POW model) |
|---|---|---|---|
| | | | specific line items. |
| **Emergency & unscheduled power system response & repair** | **$13,095** | **Consistent**<br>Base line is maintained as $13,095, with the actual at $13,446 for that year | **Almost consistent**<br>Using all programs allocated to the RIN, non-routine emergency response category.<br>Program opex allocated to this category ranges from $13.7m to 13.0 m across the next period. |
| **Vegetation management** | **$8,859** | **Consistent**<br>No reduction is applied, but it appears that the 2010/11 actual is already below our upper limit | **Almost consistent**<br>Using all programs allocated to the RIN, categories:<br>• Non-routine vegetation management – approximately $0.92 per annum<br>• Routine – vegetation management – approximately $8.88m per annum |
| **Other** | **$1,060** | **Consistent**<br>2010/11 base line is still be $1,060, with $1,831 actuals for that year | **Not consistent**<br>Using all programs allocated to the RIN, categories:<br>• Non-routine other - $0.9 to $0.83m (mainly PQ program)<br>• Routine – other - $0.64m to $0.6 (mainly all oil management)<br>The main increase appears to be due to the PQ metering costs of $.85m, not our reduced finding of $0.4m. There are also some smaller items, but these are far less significant. |

Based upon the above, Aurora's 2010/11 base-step-trend model reflects our previous findings for all categories, other than Network Management categories. However, this position is broadly in line with the revised proposal statement noted above with regard to the elements that Aurora has included in its revised proposal. The main difference here appears to relate to the maintenance – other category, where the 2010/11 base-step-trend model appears to include our findings, although the revised proposal suggests it may not.

In the case of the network management – direct category, we have not been able to confirm with certainty whether the base line does reflect our findings. Our original base-line estimate of $8.1 million allowed for a reduction from the 2009/10 actual amount to account for an impending restructuring exercise that Aurora has been going through since that time. The equivalent adjustment in the Aurora 2010/11 base-step trend model to the 2010/11 actual indicates a 2010/11 base line for this category of $11.1 million – a significant increase from our estimate. However, in deriving the base line for the overall operating cost category (of which network management costs is a component), the model makes a $5.8 million downward adjustment to account for “non-recurrent” expenditure associated with “Distribution Business Restructure”. As such, it may well be that this adjustment accounts for the reduction we allowed for in our original estimate.

It has been more difficult to confirm matters with regard to Aurora’s program of works model (POW model). This is due to two reasons. Firstly, as it is based upon works items, it does not explicitly categories costs associated with network management and GSL payments. As such, it has not been possible to confirm these three categories.

Secondly, we understand that the POW model allows for some overheads and escalations. As such, we cannot see a direct reconciliations to our original findings. Nonetheless, it would appear that Emergency Management and Vegetation Management opex forecast do broadly align with our findings.

The maintenance-other category does not align. This appears to be due to the costs excluding a reduction we proposed associated with a program to address power quality issues. It is noted that this seem to contradict the 2010/11 base-step-trend model, which appeared to apply our findings.

## 5.2 Review of the AER’s STIPIS target calculations

### 5.2.1 Background

The AER has developed a model to determine the SAIFI/SAIDI STPIS targets for Aurora for the next control period. The methodology to derive the targets is based largely upon the following two principles:

- the average of the historical performance over the 5-year period from 2007 to 2011
- adjustments to account for the anticipated further improvement in reliability in the current period, due to specific reliability improvement programs (TRIPs).

The AER has requested Nuttall Consulting to review the AER’s calculations to derive the SAIFI/SAIDI targets, and in particular the AERs adjustments to account for the anticipated improvement in actual reliability due to TRIPs.

The key aims of the review are to:

- assess the rationale for making the adjustments associated with the reliability improvement programs
- undertake a high level review of the spreadsheet calculations.

### 5.2.2 Review

To undertake this review we have been provided with the AER models. We have also held a meeting with AER staff to discuss the rationale and calculations.

***Appreciation of rationale and calculations***

We understand that the AER's rationale for adjusting the targets is as follows:

- The STPIS guidelines require the AER to adjust targets to account for reliability improvement programs that were funded by the existing regulatory control.
- Aurora was funded to meet or better the TEC reliability standards through specific programs (known as targeted reliability improvement programs, or TRIPs) in the current period.
- The AER considers that OTTER's previous determination and Aurora's 2007 proposal support this view.
- Therefore, in setting the targets, it is appropriate to make a downwards adjustment to historical interruptions. This adjustment is set to ensure that the forecast targets would allow the TEC minimum reliability standards to be met if the TEC standards are not presently complied with.

We have reviewed the AER's calculations and summarise our understanding of these as follows.

| Step | Calculations |
|---|---|
| 1 | The 5-year average SAIFI/SAIDI in each Aurora area is calculated, based upon the TEC definition of excluded events.<br><br>This makes use of a pivot table to summate "kVA interrupted" and "kVA duration" for interruption events in each area. Event cause codes are used to exclude events associated with the TEC definition of excluded events. |
| 2 | For each area, the percentage adjustment to actual average reliability (i.e. the value from Step 1) that would be required to achieve compliance with the TEC standards is determined. If compliance is already achieved, a zero percentage adjustment is given. |
| 3 | Using the percentages from Step 2, adjustments to the raw outage data are applied to ensure that TEC standards in the relevant areas will be complied with.<br><br>The percentages are applied globally across all relevant events in an area.<br><br>This adjusted events represents the *expected* outcome for each historical event, assuming the TRIPs have achieved their intended purpose to the minimum extent possible i.e. ensuring that the TEC standards will be achieved. |

| Step | Calculations |
| --- | --- |
| 4 | The major event days, based upon adjusted kVA duration values calculated in Step 3, are determined. This is based upon the STPIS definition of major event days.<br><br>This makes use of a pivot table to summate adjusted daily interruptions, based upon the STPIS definition of excluded events.<br><br>This reflects the *expected* major event days for the historical data, assuming the TRIPs have achieved their intended purpose to the minimum extent possible i.e. ensuring that the TEC standards will be achieved. |
| 5 | The STPIS targets are calculated, based upon the 5-year average of the adjusted outage data (Step 3), and excluding major event days and other STPIS exclusions.<br><br>This makes use of a pivot table to summate adjusted interruption events, based upon the STPIS definition of excluded events. |

***Views on approach***

With regard to the rationale and overall approach to implement this, we consider this seems reasonable. In arriving at this conclusion, we consider the following points are relevant.

- We agree that OTTER appears to have provided the funding to undertake the TRIP programs, with the intention that these would allow Aurora to achieve compliance with the TEC standards[163]. Also, we are not aware of any matters raised in Aurora's planning documents that suggest these programs have not been implemented as originally planned – at least in terms of achieving the original intention. Of particular note here is Aurora's reliability management plan, which states that "the work do (sic) date has focussed on the step change improvements necessary to bring community performance to the required level"[164]. As such, noting the STPIS guidelines, it seems reasonable to assume that the reliability associated with any area that is presently non-compliant with the TEC standards should be adjusted to at least reflect these TEC standards.

- As discussed in Section 3.3.1, we consider that Aurora's trend in reliability performance over the current period and increases in non-demand driven capex over the previous period, suggest that reliability has been improved by more than just the TRIP programs in the current period – particularly in terms of SAIFI. As such, if anything, we believe that adjusting the targets to only reflect changes through the TRIP programs is probably a fairly conservative position. That is, we

[163] OTTER Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Final Report and Proposed Maximum Prices, September 2007, pg 103

[164] AE025, pg 13

consider it likely that the *expected* performance at the commencement of the next period may be materially better than reflected by the STPIS targets[165].

- We believe the AER's approach of adjusted actual outage data in order to infer the ongoing impact of the TRIPs to the end of the current period is a reasonable approach. This approach seems to transparently and objectively allow the requirement to comply with the TEC standards by the end of this period, to be incorporated into the calculation of the STPIS targets.

With regard to the approach to calculating the STPIS targets and associated adjustments, we have undertaken a high-level review of the AER's spreadsheets. Although we cannot claim that this review has been sufficient to provide positive assurance on the validity of the calculations, we can advise that we have not found any major issues with the calculations[166].

In arriving at this view, we have attempted to follow the overall logic of the various spreadsheets, including:

- the various pivot tables, and the categories used to exclude events
- the various lookup tables, and their uses
- the calculations associated with determining average reliability and adjustments at the TRIP area level
- the calculations to adjust actual "raw" outage data
- the calculations to determine major event days
- the calculations to determine the STPIS targets.

[165] Is worth noting however that this view is as much about the STPIS guidelines requiring the use of a 5-year average to predict the expected outcome, as the implications of the TRIPs.

[166] Our review did find an inconsistency in the classifications used in one of the pivot tables. These classifications were used to define STPIS excluded events. However, this issue was advised to the AER and had been addressed in a later version of its model that was provided to us for review.

# 6 Alternative control

Nuttall Consulting has been requested by the AER to investigate a number of specific technical aspects relating to the Aurora Energy revised proposal on Alternate Control Services. The specific items for review include:

1 Public lighting - assessment of the reasonableness of:

   a. Aurora's bulk replacement lamp cycle

   b. public lighting service standards associated with bulk replacement

   c. cost trends for bulk replacement

   d. the specific replacement of a particular fitting type.

2 Metering – assessment of the reasonableness of Aurora Energy's proposals for the following items:

   a. an appropriate value for timeclocks

   b. customer initiated meter changes

   c. replacement costs for electronic meters.

3 Fee based services - analysis of the prices for the following services:

   a. Site visit – credit action or site issues

The following sections details the Nuttall Consulting review of these items.

## 6.1 Public lighting

Aurora has made a single alteration to the public lighting costs proposed in the original Aurora proposal. This alteration addresses a return to a bulk replacement program for public lights. This proposed change was not identified in the original Aurora proposal.

Nuttall Consulting has reviewed the revised bulk replacement approach and considered the following aspects relating to the revised expenditures:

- current replacement cycle period
- trends in public lighting service levels
- public lighting cost trends
- specific product assessment.

### 6.1.1 Replacement cycle

Bulk replacement of public lighting lamps (i.e. the globes that sit inside the housings) is a standard practice for most Australian distribution businesses. This practice is considered cost effective and is also consistent with meeting the Australian standard for public lighting[167].

The Aurora public lighting management plan[168] articulates a 4-year bulk replacement program with a supplemental program to repair lights that fail in between the replacement cycles.

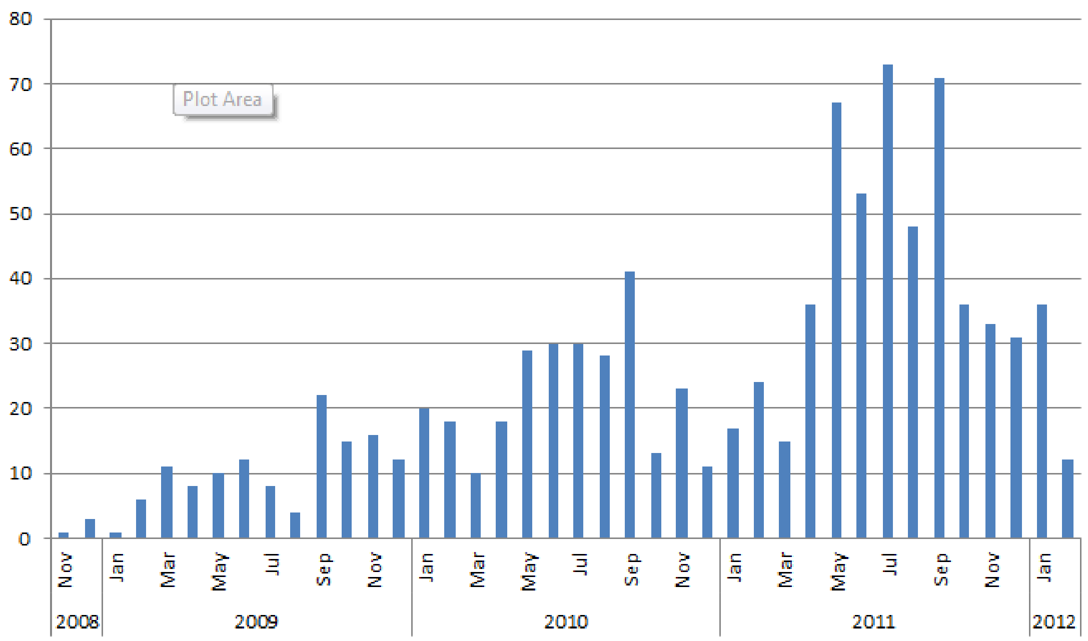
Aurora has identified that it is currently lagging the current bulk replacement program by 1 year[169] and that this backlog in lamp replacement has resulted in additional expenditures associated with lamp failures.

Nuttall Consulting has considered the information provided by Aurora and agrees that it appears that a backlog in bulk lamp replacements has built up in the last 1 to 2 years. This backlog is not considered consistent with good industry practice or with Aurora's stated asset management plans.

### 6.1.2 Service levels

Nuttall Consulting has reviewed the lamp failure rates and confirms that a significant increase in lamp failures is evident from the information provided by Aurora. The following figure highlights both a longer term increase in failure rates and a very large increase in 2011.

**Figure 3 Public light failure rates**




We have also considered the costs associated with public lighting failure rates. Aurora has provided the following historical expenditures associated with public lights[170].

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[167] AS/NZ1158

[168] Management Plan 2011, Public Lighting, Document Number: NW#-30148124-V5, 9 May 2011

[169] Section 2.3 - AE112 - Aurora Response - Public Lighting.pdf

**Table 17 Public light failure expenditure ($2009/10)**

| | 2006/07 | 2007/08 | 2008/09 | 2009/10 | 2010/11 |
|---|---|---|---|---|---|
| **Expenditure** | 866,864 | 839,823 | 869,227 | 1,285,884 | 1,097,612 |

The above table indicates that emergency repair expenditures were at their peak in 2009/10 and then reduced slightly in 2010/11. This information is not consistent with the failure rates reported by Aurora where 202 light failures were reported in 2009/10 and 358 failures in 2010/11. This represents a failure rate increase of 77% while the costs associated with the failures decreased.

It is likely that there is an error in one set of data (failure rates or associated expenditures), although we are unable to determine where this error lies.

The increase in failure rates is very significant. As indicated by Aurora, it would appear likely that much of the increase in failures was due to the deferral of the bulk replacement program. This therefore represents an overall reduction in expenditures that has resulted in a real reduction in service levels to the consumer.

We do not consider that this backlog of bulk replacement streetlights should be funded in the next period as this expenditure has already been allowed for in the current period. From our review we consider that this backlog is not contained in the Aurora proposed volumes and we therefore accept those volumes.

### 6.1.3 Cost trends

The following table provides the expenditures associated with bulk lamp replacements in the past 3 years.

**Table 18 Public light bulk lamp replacement expenditure ($2009/10)**

| | 2006/07 | 2007/08 | 2008/09 | 2009/10 | 2010/11 |
|---|---|---|---|---|---|
| **Expenditure** | - | - | 742,936 | 1,053,255 | 888,285 |

The first four-year bulk lamp replacement program commenced in 2008/09 and is programmed to run until 2011/12. This program has targeted the removal of switch wire[171] in remote townships where there are increased travel times to respond to faults (and therefore increased costs). The second bulk lamp replacement program is programmed to commence 2012/13 and run until 2015/16. The second bulk lamp replacement program will be targeting the removal of all switch wire and relays in minor road areas.

[170]Public Lighting 2a&b.xls

[171] Additional low voltage conductor on overhead systems to control the timing of a set of public lights – now redundant with the installation of individual photo-electric controllers on each lamp.

According to the Aurora responses[172], the current bulk replacement expenditures represent an outcome that is one year behind the original program. In other words, the expenditures incurred represent 3 years of a program that will take 5 years to complete.

If we consider the average of these three years of expenditure and then account for the program returning to a 4-year cycle, the annual expenditure level should be $1,118,532[173].

This annual expenditure level does not account for any changes in the switch wire replacement programs. Aurora has not identified the specific costs associated with the switch wire removal programs (current or proposed). However, we consider that the removal of category P switch wires (minor roads) would involve a greater volume of work than the removal of switch wires in remote townships.

We note that Aurora has reduced the forecast expenditure associated with public lighting emergency repairs and maintenance[174] consistent with the return to a 4-year bulk replacement cycle.

### 6.1.4 Individual product fitting replacement

Aurora has made an additional change to the opex forecast based on the volume of lamps to be replaced under the Bulk Lamp Replacement program.

There are approximately 16,300 Sylvania B2224 luminaires in the Aurora fleet of 48,000 lamps. The majority of these Sylvania lamps were installed between 1989 and 2004. On the basis of a standard 20-year life for luminares, units installed before 1998 will be beyond their standard life by the end of the next period.

Aurora has stated[175] that it intends to replace these luminaires at a rate such that no luminaires in the fleet will be more than 20 years old by the end of the next period. As a consequence, Aurora is proposing to replace approximately 9,000 luminaires in the next period.

We requested that Aurora provide justification for replacement of Sylvania B2224 light fittings that are less than 20 years old as the current program appeared to be replacing fittings that are as young as 5 – 10 years.

Aurora responded that[176]:

- Sylvania B2224's that are not stamped with any labelling on the underside of the luminaire have been deemed to be installed in 1995 or earlier. Post 1995, the fittings were stamped with the wattage rating and the year of manufacture.
- Target the replacement (in the next period) of B2224 fittings that are in the age range comprising 1989-95 (Sylvania B2224 fittings were first installed in 1989).

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[172]Section 2.3 - AE112 - Aurora Response - Public Lighting.pdf
[173] $2009/10
[174]RLREM - Major / Minor Road lighting Inspection / Repairs - general
[175]Section 2.3.1 - AE112 - Aurora Response - Public Lighting.pdf
[176]AER Response AER-058.pdf, question 5

We have reviewed the information provided by Aurora. We also note that concerns with failure rates, lumen depreciation and the availability of newer technologies mean that the replacement of this category of lamp type is reasonable and consistent with other Australian DNSPs.

We consider that this additional replacement program is reasonable.

### 6.1.5 Summary

In summary we consider that the additional expenditure associated with a return to a 4-year bulk lamp replacement cycle is reasonable. The proposed staged replacement of the Sylvania B2224 luminaire is also considered reasonable.

## 6.2 Metering

The AER has requested Nuttall Consulting to consider three aspects of Aurora's proposed expenditure forecast associated with metering. The following describes the requested areas for the review:

- the appropriateness of, and valuation for, incorporating time clocks into the RAB for Aurora's metering services
- Aurora's proposed metering capital expenditure for customer initiated additions and alterations
- Aurora's proposed replacement costs for electronic meters.

Each of the above items are considered in the following sections.

### 6.2.1 Timeclocks

In their revised regulatory proposal[177], Aurora states that the AER has failed to account for the timeclocks in the meter asset base. In particular, timeclocks that are installed with mechanical meters and are used to provide an off peak tariff to customers.

Aurora notes that these timeclocks were treated as off peak meters as part of the OTTER modelling and has now included them as part of the establishment of the initial regulatory asset base (RAB) for meters.

Aurora's inclusion of these timeclocks adds an additional $1.03 million to the valuation of the initial RAB. This is based on a reported population of 20,997 timeclocks[178].

Aurora notes that as it has not installed mechanical meters with associated timeclocks since the commencement of the current control period it will not require timeclocks in the next control period[179].

[177] Aurora Energy Revised Regulatory Proposal 2012–2017, Aurora, P141
[178] AE142 - Metering Revenue Model.xls – single and three phase.
[179] The features of a timeclock (i.e. a timing device and a switch) are now incorporated in the standard Aurora electronic domestic meter.

As a starting point, Nuttall Consulting notes that timeclocks have been a necessary and common item in metering installations where time-of-use tariffs are used. They are now superseded by electronic meters which often include the features previously provided by a standalone timeclock.

It would be inefficient to replace all the timeclocks currently operating in Aurora's network, although the natural replacement cycles will likely accomplish this over the next 20 to 30 years. A shorter replacement timeframe may eventuate should a smart meter rollout be undertaken for all customers in Tasmania.

Aurora was requested to provide the most recent contract or tender for the provision of mechanical timeclocks. Aurora responded[180] that the most recent bulk purchase of new timeclocks occurred prior to 2007 and did not provide any additional details.

Aurora has utilised an average cost of $71.13[181] as the purchase cost of a timeclock.

The installation of a timeclock also includes:

- a supply fuse for timeclocks to allow de-energisation
- a load control relay for three phase loads (approximately 750 installed)
- an additional meter panel for installations with three tariffs (or three mechanical meters).

The above items would add to the overall cost of timeclock installation.

Information on timeclock costs is not publicly available due to them being superseded by electronic meters and timeclocks. Nuttall Consulting has reviewed the meter asset base costs used for the 2007 electricity distribution pricing determination in Victoria and notes that the asset value that is attributable to timeclocks is consistent with the value being proposed by Aurora.

On the basis of the Victorian benchmark cost and our high-level assessment of the costs associated with a timeclock installation we consider that the unit rate proposed by Aurora is reasonable.

We note that Aurora utilises refurbished timeclocks in some situations. This would appear a reasonable approach where a full replacement of the metering infrastructure is not warranted. In these instances the refurbished timeclock would be considered to have a new value similar to its original replacement value.

### 6.2.2 Customer initiated meter changes

Aurora has proposed additional capital expenditure associated with the customer initiated meter alterations and additions. In this review we consider the two components of the customer initiated meter charges; (i) the unit cost and (ii) the volume of activities. At the conclusion of this section, we have also considered new information provided by Aurora relating to the abolishment of meter installations.

[180] AER Response AER-058.pdf

[181] AE142 - Metering Revenue Model.xls – $2011/12

**Customer initiated unit costs**

Aurora has identified two separate cost components for this work. The first cost is the labour cost of installing or altering the meter[182]. These costs are recovered through a customer based fee and are not the subject of this review.

The second cost component is the meter purchase cost. Aurora is proposing that this second cost component be recognised in the regulated asset base for meters.

To assess the prudency and efficiency of these proposed costs, we have sought to determine the scope of activities and assets covered by customer initiated additions and alterations. Aurora has indicated that these works are the result of customers requesting that a meter location be moved or that an alternate tariff is applied to the installation (requiring new or altered metering equipment).

To support the proposed costs Aurora advised that it has a policy of replacing meters that have (a) failed compliance testing or (b)are very old and in poor condition[183]. These two triggers are considered in more detail below.

When Aurora crews attend a site to install an additional meter for a new tariff and a meter type that has been identified as requiring replacement is installed on the existing tariff, it is removed and replaced whilst the crew is on site. This removes the need for a second visit in the future to replace the existing meter.

We concur that it is most efficient for Aurora to replace a meter that is identified as having failed compliance testing when works are being undertaken on site. However, the meter replacement program has already made allowance for the replacement of these meters including the associated installation costs (labour and materials). On this basis, the request by Aurora for meter replacement costs associated with alterations and additions represents a double counting of future capex requirements.

The replacement of "very old and in poor condition" meters may or may not be efficient. Aurora has provided no justification that this approach is more efficient than replacement when the meter population fails compliance testing. On this basis we cannot recommend the additional capex associated with the replacement of these meters. We consider that the existing methodology of replacing the meter population based on sample testing for compliance should remain.

In summary, we cannot recommend the proposed expenditure for metering alterations and additions as proposed by Aurora.

**Customer initiated work volumes**

Aurora is proposing significant metering work volumes associated with alterations and additions. The draft determination did not provide for any work volumes in these categories. The volumes contained in the Aurora resubmission are provided in the following table.

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[182] This may include small a small materials component associated with the meter alteration (e.g. cabling, meter board, etc).

[183]AER Response AER-058.pdf

**Table 19 Alterations and additions - proposed volumes**[184]

| | 2012-13 | 2013-14 | 2014-15 | 2015-16 | 2016-17 |
|---|---|---|---|---|---|
| **Additions** | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 |
| **Alterations** | 5,500 | 5,500 | 5,500 | 5,500 | 5,500 |

Aurora has provided the following descriptions for alterations and additions[185].

- Alterations – Alterations relate to existing meters replaced when customers upgrade or modify existing dwellings such as upgrading consumer mains or relocating the meter box. Volumes have been forecast using historical volumes as a basis.
- Additions - Additions relate to additional meters installed as a result of customers adding additional tariffs to existing dwellings.

As both of these activities are customer initiated, Aurora has very limited control of the actual volumes of activity. Most likely, activity will be driven by external factors such as retailer activity and promotion of off-peak products such as hot water heaters, air-conditioning and under-floor heating. Increases to overall electricity prices may also impact the rate at which customers look to save money through alternative tariff structures. As such, the use of historical work volumes to forecast future requirements is considered reasonable.

Aurora has provided the following historical information on alterations and additions[186].

**Table 20 Alterations and additions - historical volumes**[187]

| | 2007-08 | 2008-09 | 2009-10 | 2010-11 | 2011-12[188] |
|---|---|---|---|---|---|
| Additions | 1,282 | 1,133 | 1,664 | 1,401 | 1,695 |
| Alterations | 2,818 | 3,358 | 3,883 | 3,268 | 3,955 |
| **Total** | **4,100** | **4,491** | **5,547** | **4,669** | **5,650** |

Whilst there is a degree of variability in these annual figures, Aurora has provided no reason why these historical volumes are not representative of the likely future volumes. We note the increasing trend in these work volumes and consider that this trend should be considered in forecasting future volumes. The following table provides our forecast work volumes based on a linear trending of the historical volumes[189].

[184] AER Response AER-058.pdf
[185] AER Response AER-067.pdf
[186] AER Response AER-058.pdf
[187] Volumes in meters (not registers)
[188] Projected
[189] Additions – 30%, alterations – 70% as identified by Aurora: AER Response AER-058.pdf

**Table 21 Alterations and additions – linear forecast volumes**[190]

| | 2012-13 | 2013-14 | 2014-15 | 2015-16 | 2016-17 |
|---|---|---|---|---|---|
| Additions | 1,762 | 1,861 | 1,959 | 2,057 | 2,157 |
| Alterations | 4,112 | 4,342 | 4,571 | 4,801 | 5,030 |
| **Total** | **5,875** | **6,203** | **6,530** | **6,858** | **7,186** |

We note that Aurora has forecast additions at 1,500 units per annum for the next control period. We are unclear as to why this amount has been proposed and consider that it may under represent of likely workload levels. On this basis we have substituted the volumes as recommended in the above table.

In relation to alteration volumes, we have considered these from two perspectives:

1 the replacement of meters that are identified as not complying with the meter test standards in accordance with Aurora's meter management plan[191]

2 the replacement of meters that are old or visually deteriorated, but are not currently identified for replacement.

These two categories are considered below.

**Meter alterations – replacement of non-compliant meters**

Meter replacements are a distinct and separate category from the meter alterations cost category. The meter replacements category covers the replacement of meter populations that have failed the meter testing procedures.

We have reviewed the information provided by Aurora relating to meter replacement. This information clearly identifies that the meter replacement program relates to the replacement of all meters that fail to comply with the meter standards. There is no mention in this information of an additional or separate category of meter replacements that are undertaken when a meter alteration is undertaken. The AER's draft determination has already made allowance for all compliance related meter replacements forecast by Aurora for the next period.

The Aurora definition for meter alterations clearly indicates that it relates to non-meter activities (i.e. moving the meter location or replacing the customer mains) and therefore provides no alternative reason to justify the replacement of the meters.

As the replacement of non-compliant meters is already funded, we are unable to recommend the additional funding associated with meter replacements under the alterations cost category.

[190] Volumes in meters (not registers)

[191] Management Plan 2011, Metering Assets, Document Number: NW30161525-V3, Aurora Energy, Date: 9 May 2011

**Meter alterations – replacement of compliant meters**

As discussed in the previous section (customer initiated unit costs), we do not consider that Aurora has provided sufficient evidence to justify the replacement of meters that are not identified as having failed the meter sampling test.

In summary, we do not consider that Aurora has proven that the proposed alteration meter replacements are justified and not a double counting of workload. We do not recommend any meter replacements be recognised in this work category.

For the avoidance of doubt; our recommended removal of the meter alteration replacement volumes should not be read as to suggesting that the overall volume of meter alterations should be removed. Our finding specifically relates only to the replacement of meters under this work category.

The following table provides our recommended work volumes for alterations and additions.

**Table 22 Alterations and additions – recommended forecast volumes**

| | 2012-13 | 2013-14 | 2014-15 | 2015-16 | 2016-17 |
|---|---|---|---|---|---|
| Additions | 1,762 | 1,861 | 1,959 | 2,057 | 2,157 |
| Alterations | - | - | - | - | - |
| **Total** | **1,762** | **1,861** | **1,959** | **2,057** | **2,157** |

**Abolishments**

Aurora is proposing the abolishment of 710 meters per annum. This is a new addition to the meter model[192].

The abolishment of a meter location is a relatively common occurrence for all distribution network service providers (or meter providers). Abolishments may be required where a dwelling, commercial or industrial site is vacated for a long period of time or is demolished.

Abolishments are also common when a premises is disconnected to allow renovations or rebuilding. In these instances, a connection is re-established once the new premises is constructed, although this can be months or even years later.

Aurora has proposed that a total meter count of 710 meters are abolished in each calendar year. No additional information has been provided to support this figure. However, we consider that this value is within reasonable bounds[193] given Aurora's total operating meter stock.

[192] These values were not included in information provided for the draft determination.
[193] Less than half of 1 per cent of total meters.

### 6.2.3 Replacement costs for electronic meters

In our original review[194] of the meter purchase costs of Aurora, we recommended that the meter purchase cost for an electronic single phase meter be set at the current (contract) value of $170 per meter with an allowance for escalation and on-costs[195]. This value was based on assumed meter volumes that were consistent with Aurora's annual installation volumes. Lower purchase volumes attracted a higher unit rate. The following table provides the meter purchase costs and associated volumes from the 14 April 2010 contract[196].

**Table 23 single phase domestic meter purchase costs**

| Quantity | Unit Price |
|---|---|
| [redacted] | [redacted] |
| [redacted] | [redacted] |
| [redacted] | [redacted] |
| [redacted] | [redacted] |
| [redacted] | [redacted] |

The original Nuttall Consulting review also noted that meter purchase value may need to be revised if the results of the meter tender process that was currently under way became available later in the review process.

Aurora has revised its single phase electronic meter purchase cost to $189[197] (exclusive of on-costs and installation costs). This unit rate of $189 is consistent with the lowest purchase quantities listed in the April 2010 quote from the meter provider[198].

In its revised submission, Aurora has provided a copy of the most recent single phase electronic meter purchase contract (signed 19 September 2011).

This contract is for the bulk supply of the meter type and has a unit rate of [redacted] The contract appears to cover the minimum meter specifications and has significant volumes – although lower than the annual Aurora meter requirements. The contract was sourced through an open tender process and Aurora has provided board papers relating to the tender selection process.

We are unable to confirm the Aurora meter purchase cost of $189 as it represents a purchase price that is now out of date.

We consider that the single phase electronic meter purchase cost of [redacted] from the current meter provider contract is reasonable.

[194] Report – Principle Technical Advisor, Aurora Electricity Distribution Revenue Review, A report to the AER Final Report, Nuttall Consulting, 11 November 2011, p178
[195] Ibid, p178
[196] QUO-01492-DPJB79-1.pdf (confidential)
[197] Metering 5a.xls
[198] QUO-01492-DPJB79-1.pdf (confidential)

In the draft determination, the AER recommended a three phase electronic LV meter purchase cost of $246.00. In its revised proposal, Aurora has utilised this same purchase price[199]. Aurora was requested to provide any new or revised meter purchase contracts from the recent re-tendering process. While a revised single phase electronic LV meter price was provided, no three phase meter updates were provided.

Aurora has provided a board paper[200] extending the April 2010 meter purchase arrangements until the end of the 2011/12 financial year. However, it is not clear if a revised three phase contract has been determined.

As Aurora was requested to "(p)rovide the most recent tenders for multiphase and CT meters"[201] we take this to imply that no new three phase meter contracts have been entered into. On this basis we consider that the three phase electronic LV meter purchase cost of $246.00 is reasonable and that the CT (LV) meter purchase cost of $384 is reasonable.

## 6.3 Fee based services

Nuttall Consulting reviewed the costings for six fee based services proposed by Aurora in their original proposal. The AER draft determination took into account the Nuttall Consulting recommendations including adjustments to the fee based services.

In its revised proposal Aurora states that it "does not accept the AER's proposed alteration to the task time associated with visits to deenergise for credit purposes or site issues"[202].

Aurora identifies that the build-up of costs for these services in its original proposal assumed an on-site time of 40 minutes. The AER did not accept this task duration, and revised the estimated task duration to eight minutes.

The revised proposal provides the following additional information:

- That these services are performed at the request of, and on behalf of, the customer's retailer.
- Rather than simply removing the fuses, as occurs for a normal de-energisation, these services require that Aurora must physically disconnect the customer premises from the distribution network.
- This may require opening a turret, in the case of an underground supply, or removing overhead infrastructure.
- Further, since these services may also be requested due to an "illegal connection", the actual physical disconnection may be at a non-standard location, and may involve the presence of police."

[199] Metering 5a.xls - Once on-costs are excluded.
[200] CO-#10391605-v1-08g_-_Meter_Supply_Contract_-_EDMI.pdf
[201] AER Response AER-067 Q8 & Q9.pdf
[202] Aurora Energy Revised Regulatory Proposal 2012–2017, Aurora, P151

The information provided by Aurora, particularly the non-standard disconnection point and the police presence, provided reason to reconsider the draft determination recommendations. The other items of information provided by Aurora were already taken into account.

Aurora was requested to provide additional information to support the revised proposal.

The Aurora response covered a 12 month period and identified the following[203]:

1. In approximately 60 per cent of cases only the fuse or link was removed.
2. Approximately 5 per cent of cases resulted in the overhead service being removed or disconnected from the premises.
3. Approximately 25 per cent of cases resulted in an underground turret being opened.
4. Approximately 10 per cent of cases were due to "other" issues[204].

Aurora also reported that there have been 6 instances where police have been requested/required on site. This represents approximately 3 per cent of all credit disconnects. In addition there have been 81 instances where an illegal connection was deenergised and disconnected (approximately 35 per cent of all credit disconnects).

Aurora also estimates that approximately 40 per cent of site visits were made at non-standard locations (where there is not generally a service fuse, for example, a turret, load-ends, overhead service, etc).

In support of the requirement for a 2-person crew, Aurora advised that it has seen a significant reduction in the number of instances (reportable events relating to safety) since the implementation of two man crews.

[redacted]

We have reviewed the information provided by Aurora and agree with the requirement for a 2-person crew for this work. This is based on the potential for increased risk from interaction with the disconnected premises owners, and the need to have two people to disconnect an overhead service.

We also concur that activities to remove the overhead service and open a turret will require additional time onsite. The involvement of police is a rare event (3% of cases), but will also require additional time onsite.

Based on our assessment of the times for each of the above activities and weighting these based on the respective volumes, we do not agree with the Aurora assessment of 20 minutes. As a substitute amount we recommend an onsite time of 15 minutes is a reasonable weighted average based on the information provided by Aurora.

[203] AER Response AER-058.pdf
[204] "other" issues were not defined.
[205] AuroraSafe Non Negotiables.pdf (confidential)