Nuttall Consulting

Regulation and business strategy

NSW DNSP reliability outcomes

Review of licence conditions

A report to the AEMC

Final Report

23 May 2012

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Executive Summary

Introduction

The NSW government has concerns that the need to comply with state reliability obligations is a primary driver for recent increases in energy bills. Consequently, the Ministerial Council on Energy (MCE) has directed the Australian Energy Market Commission (AEMC) to undertake a review of NSW distribution reliability outcomes.

The three NSW distribution network service providers (DNSPs), Ausgrid, Endeavour Energy (Endeavour) and Essential Energy (Essential) must plan and operate their networks to ensure they comply with NSW licence conditions associated with the reliability of the electricity supply to customers. The current licence conditions on these matters were amended in 2007. The intention of the AEMC review is to provide the NSW government with a framework and information to decide whether it would be appropriate to amend the existing licence conditions.

Nuttall Consulting has been engaged by the AEMC to assist in this review. Our terms of reference cover two parts:

- the development of four reliability-outcome scenarios (three are intended to achieve a reliability-reduction outcome and one a reliability-improvement outcome)
- a review of the DNSPs' capital expenditure (capex) and reliability forecasts for these four scenarios.

This report details these activities.

To develop the scenarios we have held various meetings with the DNSPs and secondments to the AEMC from the DNSPs, and been provided with the DNSPs views on suitable changes. Based upon this, we have developed each scenario as a set of specific changes to the existing licence conditions. We have then developed an information request to obtain the DNSPs' capex and reliability forecasts associated with these scenarios, and the details of the underlying forecasting methodology.

The DNSPs have been required to prepare forecasts over a 15-year period. We have also requested a forecast for the existing licence conditions (the base case) to aid in the appreciation of the relative change.

To assess these forecasts, we have reviewed the material provided and held further meetings with the DNSPs and secondments. This review has resulted in a number of changes and revisions to the DNSPs' forecasts. This report discusses the final forecasts and does not discuss these updates and revisions.

Due to the short time frames for this review, we cannot claim that this review has been exhaustive, and it has not included any formal independent benchmarking. Nonetheless, we believe it has been sufficient to provide a reasonable degree of confidence in the validity of the forecasts, suitable for the AEMC review.

The existing licence conditions

The licence conditions have three schedules that reflect different aspects of network management and planning, as follows:

Schedule 1 – design planning criteria

Schedule 1 defines the standards (or criteria) that the network should be designed to in order to meet peak demand under different circumstances. The criteria do not involve explicit reliability standards; instead, they are based upon typical deterministic planning criteria sometimes referred to as N, N-1 and N-2 standards. Different criteria are defined for different elements of the network to reflect the level of reliability required. The criteria can be considered in terms of three parameters:

- security (or redundancy) level, which defines the amount of redundancy the network must be designed to have (i.e. N-2, N-1 ,N design)
- load at risk, which defines the amount of the demand that can exceed the security level before the network would be deemed to be non-compliant
- customer restoration duration, which defines the switching and restoration arrangements necessary to restore interrupted load (i.e. to achieve the security level).

These criteria must be complied with for a maximum demand with a 50% probability of exceedance.

Schedule 2 – reliability standards

Schedule 2 defines explicit standards that the network must meet with regard to the reliability of the supply to customers. The standards are defined in terms of certain supply types (i.e. CBD, urban, etc) and define the average reliability that these supply types should achieve in any year.

Schedule 3 – individual feeder standards

Schedule 3 defines explicit reliability of supply standards that individual distribution feeders should be assessed against. Like Schedule 2, these standards are defined in terms of certain supply types (i.e. CBD, urban, etc).

The four reliability-outcome scenarios

The four reliability-outcome scenarios have been defined based upon specific changes to the existing licence conditions. Each scenario can be understood best with reference to the three schedules as follows.

<table>
<tr><th></th><th colspan="3">Reliability-reduction</th><th>Reliability-improvement</th></tr>
<tr><th></th><th>Scenario 1</th><th>Scenario 2</th><th>Scenario 3</th><th>Scenario 4</th></tr>
<tr><td>Schedule 1</td><td colspan="3">The load at risk criteria has been used as the main parameter to drive the reliability-reduction outcome. Increasing levels of load at risk have been permitted as the scenarios move from Scenario 1 to Scenario 3.

Other changes to specific criteria have also been included to address specific conditions that we believe could result in sub-optimal design. These changes cover:
- criteria associated with maximum permissible normal loading
- criteria that define when a radial supply is acceptable.</td><td>To simplify the analysis for this scenario, the existing criteria were maintained. However, the DNSP was required to assess compliance for a more onerous maximum demand (the 10% probability of exceedance).</td></tr>
<tr><td>Schedule 2</td><td colspan="4">The existing standards were not changed. However, to allow for the variability in reliability, we proposed the introduction of a confidence level that the standard would be complied with in any year.

For the reliability-reduction scenarios, this confidence level ranged from 75% for Scenario 1 to 50% for Scenarios 2 and 3.

For the reliability-improvement scenario, the confidence level was set at 99%.</td></tr>
<tr><td>Schedule 3</td><td colspan="4">Two changes were proposed.
1) The introduction of a cap on the number of non-compliant feeders that should be addressed each year. For the reliability-reduction scenarios, this cap ranged from 4% of the total number of feeders for Scenario 1 to 1% for Scenarios 3. For the reliability-improvement scenario, it was set at 10%.
2) A change to the existing standards. For the reliability-reduction scenarios, an increase of 10% and 20% were applied for Scenarios 2 and 3. For the reliability-improvement scenario, a reduction of 10% was applied.</td></tr>
</table>

The capex and reliability forecasting methodologies

As we would have expected, the DNSPs have used different methodologies to forecast capex and reliability associated with compliance to the three schedules of the licence conditions. The methodologies are similar across the scenarios. Broadly, the DNSPs have approached the forecasting using similar methodologies and underlying principles. In general, we consider that the DNSPs have explicitly modelled the effects of the most significant changes we proposed for each scenario.

Schedule 1 modelling

For all DNSPs, the modelling of the three reliability-reduction scenarios has focused on the changes to the load at risk criteria (and associated security level). The effect of the changes to these criteria has largely been used to estimate the change in timing of projects in the base case (for the capex change) and the expected energy not served associated with this criteria (for the reliability change). Due to time constraints, the other specific changes have not been explicitly analysed by the DNSPs.

We consider that the change to the load at risk criteria should have the most significant effect on capex and reliability, and therefore, we have not rejected the forecasts because of these omissions. We do however consider that the methodologies that the DNSPs have used to estimate the reliability change associated with distribution feeders may significantly overstate the reliability changes.

For the reliability improvement scenario, all DNSPs have provided forecasts with some issues. These issues appear to have arisen as this scenario was not considered likely to be a credible preferred outcome, and as such, the DNSPs did not expend much effort on this forecast. At a general level, we agree, and therefore, we have focused our effort on correcting the reliability-reduction scenarios. Therefore, these issues remain in the current forecasts.

Schedule 2 and 3 modelling

We have accepted the forecasts associated with Schedules 2 and 3; however, we do have some concerns associated with these forecasts as follows:

- For Schedule 3, across all scenarios, Essential has forecast that a significant and constant number of feeders will be found each year to be non-compliant. In our view, there is still a possibility that this amount will trend down reducing the capex and reliability change, particularly over the medium to long term.
- For the reliability improvement scenario, Ausgrid has used historical costs to determine future capex to comply with Schedule 2. It is forecasting the need for some significant reliability improvements associated with this scenario. These historical costs are probably satisfactory for small reliability improvements. However, in our view, it is likely that it will be increasingly costly to achieve the more significant reliability improvements. As such, we believe Ausgrid may be understating the capex change associated with this scenario.
- For the reliability improvement scenario, Essential has not carried the reliability-improvement, associated with compliance to Schedule 2, forward through the forecasting period. As such, we believe that Essential is understating the reliability improvement for this scenario.

The capex and reliability forecasts

The tables below provide a summary of the capex and reliability forecasts associated with each scenario.

Across all scenarios, Schedule 1 is the most significant part of the licence conditions with regard to capex requirements. Essential is the only DNSP that is anticipating significant levels of capex associated with the other schedules, namely Schedule 3. This difference is as may be expected given the far more rural nature of Essential's network.

Schedule 2 has the least significant effect on the capex change, with only Ausgrid forecasting a small change associated with the three reliability-reduction scenarios. This lack of sensitivity appears to be because the DNSPs already comply with the standards to a high confidence level, and therefore, are not anticipating significant capex to maintain compliance. Ausgrid however is forecasting a more significant change associated with the reliability-improvement scenario.

		Capex change ($ millions)			
		Scenario 1	Scenario 2	Scenario 3	Scenario 4
Schedule 1	*Ausgrid*	*-314*	*-551*	*-573*	*42*
	Endeavour	*-128*	*-976*	*-1,184*	*970*
	Essential	*-40*	*-59*	*-78*	*-*
	Sub-total	**-482**	**-1,586**	**-1,834**	**1,012**
Schedule 2	*Ausgrid*	*-4*	*-4*	*-2*	*65*
	Endeavour	*-*	*-*	*-*	*-*
	Essential	*-*	*-*	*-*	*6*
	Sub-total	**-4**	**-4**	**-2**	**71**
Schedule 3	*Ausgrid*	*-*	*-7*	*-13*	*5*
	Endeavour	*-*	*-9*	*-33*	*79*
	Essential	*-15*	*-376*	*-556*	*530*
	Sub-total	**-15**	**-392**	**-602**	**615**
Total		**-501**	**-1,981**	**-2,438**	**1,698**

		Change in expected energy not served (MWhr)			
		Scenario 1	Scenario 2	Scenario 3	Scenario 4
Schedule 1	*Ausgrid*	*485*	*1,469*	*2,457*	*-41*
	Endeavour	*214*	*1,597*	*1,639*	*672*
	Essential	*33*	*59*	*88*	*-*
	Sub-total	**732**	**3,125**	**4,185**	**631**
Schedule 2	*Ausgrid*	*106*	*99*	*70*	*-5,135*
	Endeavour	*-*	*-*	*-*	*-*
	Essential	*-*	*-*	*-*	*-133*
	Sub-total	**106**	**99**	**70**	**-5,268**
Schedule 3	*Ausgrid*	*-*	*504*	*1,081*	*-567*
	Endeavour	*-*	*87*	*212*	*-498*
	Essential	*209*	*4,987*	*5,462*	*-417*
	Sub-total	**209**	**5,578**	**6,755**	**-1,482**
Total		**1,048**	**8,802**	**11,010**	**-6,120**

With regard to reliability changes, for Ausgrid and Endeavour, Schedule 1 is still the most significant for the three reliability-reduction scenarios. However, for Essential, Schedule 3 becomes very significant for Scenarios 2 and 3, and tends to dominate the overall change.

This high sensitivity for Essential is due to the interaction of the high number of non-compliant feeders it is forecasting each year (noted above) and the cap that we have introduced. For these two scenarios, the cap is well below the number of non-compliant feeders. As such, the number of non-compliant feeders, not being addressed, escalates through the study period. This action provides a relatively constant reduction in capex, but results in an escalating level of unserved energy. For the other DNSPs, the cap is well above the number of non-compliant feeders they are forecasting to find, and so, this issue does not affect them.

With regard to the reliability-improvement scenario, due to the limitations noted above, greater care is required in interpreting the reliability change. Nonetheless, it is clear that Ausgrid is forecasting a significant improvement in reliability associated with the high confidence level applying to the standards in Schedule 2.

Concluding comments on changes to the licence conditions

Based upon our review of the DNSP forecasts, we consider that the following points are important when considering changes to the licence conditions.

Changes to Schedule 1 to achieve a reliability-reduction outcome

- Although not all the specific changes to Schedule 1 have been modelled in detail, we still consider that the set of changes in each scenario can be considered together. The only exception to this would be the change we have proposed to the criteria when radial sub-transmission arrangements are appropriate (Scenarios 2 and 3).

  In the existing licence conditions, sub-transmission lines and zone substations outside the Sydney CBD are permitted to be a radial design, if their maximum demand is below 10 MVA (15 MVA for Essential). Sub-transmission substations on the other hand must all be N-1 (N-2 in the Sydney CBD) irrespective of their maximum demand.

  For Scenarios 2 and 3, we increased this maximum demand break point to 15 MVA and 20 MVA respectively. We also relaxed the criteria on sub-transmission substations, permitting those substations outside the Sydney CBD with a maximum demand below the break point to be a radial design.

  In the case of our proposed increase to the break point, we believe it is likely that customers supplied by the network, specifically affected by this change, could have significantly reduced reliability, even if the overall effects of the set of changes across all customers is found to be acceptable[1]. Therefore, the AEMC could consider removing this change from Scenarios 2 and 3. However, the change permitting a radial design for lightly loaded sub-transmission substations could remain.

- The reliability results may suggest that the more extreme reliability-reduction scenarios have positive net benefits. If this is the case then the scale of possible events and un-modelled

[1] In effect, we believe that an additional scenario that did not include these specific change most likely would be found to have greater net benefits.

risks may need to be carefully considered. For example, additional criteria could be added that define the maximum size in terms of customer numbers, or minutes, or energy not supplied. Determining such an event however may require careful consideration and analysis to ensure that sub-optimal criteria are not defined that effectively supersede the load at risk criteria.

Changes to Schedule 2 – all scenarios

- Schedule 1 and Schedule 3 may affect overall reliability in any year. For example, the expected energy not served resulting from the load at risk parameter associated with Schedule 1 can lead to lumpy changes in the expected or actual reliability in any year. Depending on the nature of individual network components, this may rise over a short period as energy at risk builds up, but then disappears when the relieving project is undertaken. Furthermore, works undertaken to address non-compliance to Schedule 3 could improve overall reliability. As such, capex to address non-compliance to Schedule 2 in one year could end up being stranded in a later year due to the effects of projects undertaken to comply with Schedule 1 and Schedule 3. To reduce the likelihood that this could occur, the AEMC could consider adding some additional wording associated with Schedule 2 to ensure that works undertaken to comply with Schedule 2 are economic over the medium-term. For example, this would require the DNSP to have regard to the future effects of Schedule 1 and 3 to ensure that Schedule 2 compliance works in the short-term were not superseded (i.e. effectively stranded) by future actions to ensure compliance to Schedules 1 and 3.

Changes to Schedules 3 – reliability reduction scenario

- Given Essential is the only DNSP that the cap has affected, and the cap has had a far more deleterious effect than we anticipated, we believe that the AEMC should consider removing this proposed change from the scenarios.

Schedules 2 and 3 – reliability improvement scenario

- At least for Ausgrid, there are significant improvements in reliability for modest increases in capex. However, as noted above, there is some uncertainty as to what the cost would be to achieve such improvements. Furthermore, the works to address Schedule 3 can improve overall reliability. For Ausgrid, this effect was significant. If the reliability-improvement scenario is showing a significant net benefit due to the changes associated with these schedules, then we believe it will be important to consider other mechanisms to achieve a reliability improvement, which can provide a better balance of the risks associated with outcomes being different from these forecasts. For example, the AER’s service incentive scheme appears to be a far more appropriate mechanism to achieve the types of overall reliability improvement that changes to Schedule 2 would achieve, and may at least partly occur through changes to Schedule 3.

1 Introduction

1.1 Background and appreciation

New South Wales has three distribution network service providers (DNSPs), Ausgrid, Endeavour Energy (Endeavour) and Essential Energy (Essential). These three DNSPs must plan and operate their network to ensure they comply with NSW licence conditions associated with the reliability of their networks[2]. The current licence conditions associated with these matters were amended in 2007.

Around this time and following, NSW DNSPs capital expenditure increased considerably. The NSW government has concerns that the need to comply with these licence conditions is a primary driver for recent increases in energy bills. As a result, the Ministerial Council on Energy (MCE) directed the Australian Energy Market Commission (AEMC) to undertake a review of NSW distribution reliability outcomes. This direction occurred in August 2011.

The intention of the AEMC review is to provide the NSW government with a framework and information to decide whether it would be appropriate to amend the existing licence conditions. Specifically, the AEMC will be providing advice to assist the NSW government to decide how best to balance the costs of providing network reliability with the benefits of that reliability. The MCE's direction provides the approach to be taken by the AEMC, including:

- consideration of best practice approaches nationally and internationally
- verification that the current licence conditions are appropriate
- estimation of the efficient cost of achieving a range of reliability outcomes
- estimation of the willingness of customers to pay for a range of reliability outcomes
- evaluation of the reliability outcomes, including a cost-benefit assessment.

Nuttall Consulting has been engaged by the AEMC to assist in this review. The AEMC has also engaged secondments from the DNSPs to assist in this review. We have been required to work with the secondments during the course of this assignment. To some degree, these secondments have formed part of the project team.

1.2 Terms of reference

The terms of reference of our assignment is focused on one element of approach set out in the MCE's direction (noted above), namely the estimate of the cost of achieving a range of reliability outcomes.

Furthermore, our terms of reference limit the scope of the assessment to:

[2] Design, Reliability and Performance Licence Conditions for Distribution Network Service Providers, dated 1 December 2007

- "realistic" costs rather than "efficient" costs – the AEMC considers that it is the role of the AER to determine efficient costs
- four reliability outcomes, one providing higher reliability and the others lower reliability.

The assignment is structured into two parts. These parts are summarised as follows:

Part A

a) development of the reliability outcomes, and the changes to licence conditions to achieve these outcomes – these are called the scenarios in this report

b) development of a request for information to be provided to the NSW DNSPs to elicit information associated with the cost estimates to meet these outcomes.

Part B

a) review of the capex forecasts provided by the NSW DNSPs

b) assessment as to whether the forecasts can be considered "realistic" estimates

c) provision of a draft report outlining the estimated costs of meeting the reliability outcomes

d) provision of a final report, based upon comments from the AEMC.

The AEMC has also requested that we extend our assessment to the reliability forecasts. The AEMC has also requested that changes proposed must broadly reflect the existing licence condition.

1.3 Important caveats

It is important that we stress two points associated with this assignment.

- Firstly, this assignment has made use of forecasts prepared by the DNSPs. These forecasts have been prepared in fairly tight timeframes. Our review has been sufficient to gain some confidence as to whether they represent a "realistic forecast" for the purposes required here. However, the forecasts and the findings presented here should not be used for other purposes. Most notably, we do not consider that the forecasts or our findings could be used for revenue setting purposes. In this regard, we have not undertaken the types of investigations and analysis that could be used to provide sufficient confidence that the forecast can be considered to represent efficient expenditure for such purposes.
- Secondly, this assignment is only considering changes that will affect reliability. This reliability relates to the reliability of supply to customers. As such, it is inherent in our development of reliability-reduction scenarios that the interruption of the supply to customers will increase. It will be the role of the NSW government to evaluate whether the change in expenditure justifies this change in reliability of supply.

It is also worth noting that for electricity distribution, reliability is normally expressed with regard to measures that reflect unreliability i.e. as the measure increases the network becomes more unreliable rather than more reliable. To avoid confusion with the terms normally used in the industry, we discuss these measures in terms of “reliability”. However, in reality, this term could probably be more correctly substituted with the term “unreliability”.

The reliability measure used is this report is *expected energy not served* (EENS). This is a statistical measure that reflects the annual amount of energy that, on average, will not be supplied to customers due to an interruption in their supply.

1.4 Structure of report

This report is structured as follows:

- In Section 2 we provide an overview of the methodology we have applied to undertake this assignment.
- Section 3 provides some background material on the three NSW DNSPs.
- In Section 4, we give a summary of the relevant parts of the existing licence conditions, providing some context to the changes we then discuss in Section 5.
- Section 6 and Section 7 provide an overview of the capex and reliability forecasts provided by the DNSPs.
- Section 8 discusses the review of the methodologies that underpin these forecasts.
- Finally, in Section 9 we summarise our findings and provide some further discussion on changes we have proposed.

2 Methodology

In line with our terms of reference, the methodology we have applied to undertake this assignment can be considered in terms of the two parts:

- Development of scenarios
- Review of the DNSP forecasts.

2.1 Development of scenarios

This phase involved the development of four scenarios, reflecting changes to the existing licence conditions. The main output of this phase was an information request to the DNSPs in order to obtain the DNSPs' capital expenditure (capex), operating expenditure (opex) and reliability forecasts.

This phase has involved the following key tasks:

- an initial review of the licence conditions (and other information provided by AEMC) in order to begin to determine the broad range of changes to the licence conditions that may be suitable
- a number of workshops with the AEMC secondments to discuss and fine-tune the options
- meetings with each of the DNSPs to discuss this assignment, and gain their views on relevant matters such as the relationship of their expenditure to the licence conditions and the suitability of various changes
- the development of a preliminary set of scenarios for comment by the DNSPs
- the development of the final set of scenarios (i.e. the four scenarios discussed in this report)
- the development of the information request, which underpinned the information provided by the DNSP in order for us to undertake the second phase of this assignment.

It is important to note that we have not undertaken any formal quantitative technical or economic analysis to guide the changes within the scenarios. Due to the time constraints, we have had to rely largely upon our judgement and the views expressed by the DNSPs and the AEMC secondments.

The information request we prepared included the following:

- A data template (in spreadsheet form) was developed to enable the DNSPs to report their capex and reliability forecasts in a consistent form.

- A series of questions was also included. The aim here was to elicit relevant information that would assist our review of the forecasts and the forecasting methodologies. These questions sought information on various matters, including:
  - description of the methodologies the DNSPs applied
  - underlying models, assumptions, worked examples
  - discussion on the proposed changes.
- General guidance on our expectations of the forecasting and information provision was also included in the request.

The data template has been an important tool for collecting forecast data, and preparing the charts and tables presented in this report. The data template defines certain aspects of the required forecasts as follows:

- The forecast study period was set to 15 years, commencing at the start of the next regulatory period (2014) (i.e. the date when the new licence conditions would be introduced). The intention of the 15-year period was to gain an appreciation of any cyclical patterns. The view here was that the recent “catch-up” in compliance that has occurred in the current period may result in a reduction in the short term, followed by an increase later.
- Forecasts were only required for components of expenditure that were directly affected by the licence conditions. We did not seek general expenditure forecasts. However, for the design criteria in the licence conditions, we did request that the DNSPs indicate what the primary driver of the expenditure was, in terms of intrinsic growth, new developments or replacement. The intention here was to better understand whether different drivers were affecting the different DNSPs. However, in reality, it was difficult to draw very much from these break downs.
- For each scenario, a year-by-year forecast of the capex, opex and reliability change was required. To aid in our appreciation of the effects of specific changes, the DNSPs were required to show the contribution that each specific change to the licence conditions had on the forecast.
- The DNSPs were also requested to provide forecasts for the existing licence conditions. The forecast was to commence in 2012 and continue through the 15-year study period. The intention here was to provide a “base case” that the changes could be compared against.
- Reliability associated with the licence condition was reported in terms of expected energy not served. Overall reliability was also required in terms of expected energy not served and SAIDI/SAIFI. The AEMC provided guidance to the DNSPs on how they should convert from one to the other. In this report, we only discuss the expected energy not served.

2.2 Review of forecast

Our review of the expenditure and reliability forecasts commenced following the provision of the data, provided in response to the information request discussed above.

The data has included:

- completed data templates
- methodology documents
- in some cases, underlying models; in others, work examples.

It is important we note that, although the data that was initially provided included completed data templates, it did not include significant detail in response to our other questions. Only in the case of Essential were we provided with relatively detailed explanations of the methodology that it had applied to derive the forecasts. In the case of Ausgrid and Endeavour, the DNSP secondments prepared methodology documents that were then revised and signed-off by the DNSPs. With regard to many of the other questions in the information request, we have not been provided formal responses.

Our review of the DNSPs' data has included the following key tasks:

- various workshops with the AEMC secondments to discuss the methodologies
- a number of meetings with the DNSPs to discuss their forecasts and underlying methodologies; this has included an onsite meeting with each DNSP and a number of telephone meetings.

It is important to note that this review has resulted in a number of updates to the templates to address issues that were found. The discussions in this report only cover the final template and methodology. This report does not cover those templates that were superseded or the issues associated with those templates.

Finally, as noted in the introduction, this review has focused on understanding forecast costs and determining whether they can be considered "realistic". The confidence in the accuracy of the forecast and findings discussed here has to be seen in the context of the time available for the DNSPs to prepare the forecasts and for us to review them.

In this regard, our findings are very reliant on the explanations provided by the DNSPs and the AEMC secondments. We have not had the time or information to perform the following:

- undertake significant independent analysis
- benchmark the forecasts or underlying costs, against each other or DNSPs in other states
- perform a forensic audit of the underlying models to ensure that they do not contain errors and are an accurate reflection of the methodology documents.

3 NSW DNSPs

This section provides some background on the three NSW DNSPs. This background is intended to show the similarities and differences between the DNSPs, in order to aid in the appreciation of findings presented in this report.

Ausgrid

Ausgrid is a predominantly urban DNSP that also services the Sydney CBD. It does however supply some rural areas on the Central Coast and in the Hunter region.

Ausgrid is the largest of the three DNSPs in terms of its load i.e. peak demand, energy, and customer numbers. It is also the largest based upon the value of its regulated asset base (RAB). In all these measures, it is approximately twice as large as the other two DNSPs. Given its predominantly urban/CBD nature, it also has the highest load density.

Endeavour

Endeavour is also predominantly an urban DNSP, but it does also supply rural areas in western Sydney and on the NSW south coast.

Endeavour is the second largest DNSP in terms of its load, and appears to have the peakiest demand. However, it is the smallest in terms of its RAB.

Essential

Essential is a predominantly rural DNSP. However, it also supplies some relatively large rural centres such as Port Macquarie, Tamworth, Queanbeyan and Albury.

It is the smallest in terms of load. However, it is by far the largest in terms of length of line, approximately 4 times larger than the other DNSPs. Hence, it also has by far the lowest load density. Due to the length of line, it has the second largest RAB.

4 The existing licence conditions

4.1 Overview

The relevant licence conditions for this study have three components that reflect different aspects of network management and planning. The standards associated with these three components are defined in three schedules within the licence conditions. The schedules and their purpose are as follows.

- ***Schedule 1 – design planning criteria***

  Schedule 1 defines the standards (or criteria) that the network should be designed to in order to meet peak demand under different circumstances. The criteria do not involve explicit reliability standards. Instead, the criteria define the level of spare capacity that should be designed into the system and time limits on its availability. These time limits reflect the switching requirements that must be designed into the network. This spare capacity is then available under certain network outages, hence, indirectly influencing the reliability of supply.

  The criteria in Schedule 1 are what are commonly termed deterministic planning standards (i.e. sometimes referred to as N, N-1 and N-2 standards). They form the key technical tests that the DNSP will apply to plan the augmentations of its network in order to meet the forecast growth in peak demand.

- ***Schedule 2 – reliability standards***

  Schedule 2 defines explicit standards that the network must meet with regard to the reliability of the supply to customers. The standards are defined in terms of certain supply types (i.e. CBD, urban, etc) and define the average reliability that these supply types should achieve in any year.

  Achieving compliance to these standards can require some targeted projects or programs. However, the standards have a relatively broad scope, as most of how a DNSP plans and operates its network can affect this reliability. As such, it could be that ensuring compliance to Schedule 1 or Schedule 3 or even some other requirements may inherently achieve compliance to these standards, without any specific actions.

- ***Schedule 3 – individual feeder standards***

  Schedule 3 defines explicit reliability of supply standards that individual distribution feeders should be assessed against. Like Schedule 2, these standards are defined in terms of certain supply types (i.e. CBD, urban, etc).

  These standards are aimed at finding poor performing feeders, and define the minimum standard below which a feeder could be considered poor performing. The licence conditions do not require each non-compliant feeder to be addressed.

Instead, they impose reporting and investigation obligations. In effect, only those feeders considered suitable for improvement need to be addressed. As such, investment decisions associated with Schedule 3 are generally reactive in nature.

The following subsection summarises key components of each of these three schedules. The aim here is to provide an overview of the schedules and draw out some of the key issues that influence what changes could be applied to these standards.

4.2 Schedule 1 – design planning criteria

The design planning criteria in Schedule 1 are categorised in terms of load, network and asset types and the maximum demand on the asset.

This categorisation is required to distinguish the broad performance requirements associated with the scale and density of demand (or customers). In this regard, higher demand levels (as will often be transmitted through sub-transmission assets) will require higher standards to achieve a level of reliability for all customers within that demand group. Conversely, as the customer density reduces, it is generally more costly (and as such, less economic) to achieve similar reliability levels to higher density customers. Differences in the economic value of the interruptions to different customer types can also drive differences in the required standard – and effective reliability.

Three load types are used that reflect the type of load being supplied, namely CBD, urban, and non-urban (or rural). The two broad network types reflect the sub-transmission network (including zone substations) and distribution network. The asset types reflect the role of assets, covering substations, overhead lines, underground lines, distribution feeders and distribution substations. The asset types in the urban and non-urban load type are also distinguished by their maximum demand.

Design criteria are then defined for each of these categories. These design criteria can be considered in terms of three components as follows:

- ***Security (or redundancy) level***

  This term defines the level of redundant (or spare) capacity that must be designed into the network. As noted above, this is typically defined as N-*x*, where *x* defines the number of network elements that can be assumed to be out of service, while still being able to achieve some form of supply to customers. Clearly, as *x* increases then reliability should increase. However, *x* must be an integer, and as such, as *x* moves from 0 to 1 and then to 2 (and above) the level of reliability will change in discrete steps. Furthermore, as the probability of a multiple network outage reduces substantially, the step increase in reliability will reduce substantially as *x* increases. This means that the increased cost of the additional asset redundancy may be substantially higher than the increased reliability. Finally, different assets can have different probabilities of an outage; as such, this needs to be considered when defining the security level for different network segments.

- ***Load at risk***

  This term defines the amount of load, energy, or time that the system is permitted to be above the security level. In effect, this term defines the maximum amount of involuntary load shedding that would need to occur should the assumed outages occur when actual conditions match the defined planning criteria – allowing for the customer restoration criteria[3].

- ***Customer restoration***

  This term defines the switching and restoration arrangements necessary to restore interrupted load (i.e. to achieve the security level). Broadly, a restoration duration of less than 15 minutes may require automatic switching, 1 hour may require remote switching and above this could be manual. It is worth noting that allowing for the security level following switching can reduce the overall level of spare capacity required within the network, as spare capacity can be shared to achieve the required security level.

Based upon the above, the existing licence conditions can be summarised as shown in the table below. The licence conditions require that these design criteria be met for a maximum demand that reflects a 50% probability of exceedance (POE).

[3] In reality, more or less load may be at risk depending on the actual conditions.

	Asset type	Security level: N-2 Load at risk	N-2 Customer restoration	N-1 Load at risk	N-1 Customer restoration	N Load at risk	N Customer restoration
CBD	**Sub-transmission**						
	Sub-trans lines, sub-trans substations, and zone substations	None	1 hour	None	No interruption allowed	None	Not applicable
	Distribution feeders and subs						
	CBD triplex system[a]	Any nonessential load is at risk	*Not defined*	None	No interruption allowed	None	Not applicable
	CBD remaining			None	No interruption allowed	None	Not applicable
Urban	**Sub-transmission (>=10 MVA)[b]**						
	Sub-trans overhead lines and zone substations			1% of time or 20% thermal capacity - Essential Energy: None	<1 minute	Thermal capacity must be at least 115% of forecast demand	Not applicable
	Sub-trans UG cables			None	<1 minute	Thermal capacity must be at least 115% of forecast demand	Not applicable
	Sub-trans substations			None	<1 minute	*Not defined, but assume must be as above*	Not applicable
	Distribution feeders and substations						
	Distribution feeders			None	<4 hours	Expected demand no more than 80% (2014) and 75% (2019) of average feeder group thermal capacity	Not applicable
	Distribution substations					*Footnote 7 of licence conditions suggests some level of redundancy expected*	Best practice repair time
Non urban	**Sub-transmission (<10 MVA)**						
	Sub-trans overhead and UG lines and zone substations					Thermal capacity must be at least 115% of forecast demand	Best practice repair time
	Sub-trans substations			None	<1 minute	*Not defined, but assume must be as above*	Not applicable
	Distribution feeders and subs						
	Distribution feeders					None	Best practice repair time
	Distribution substations					None	Best practice repair time

a – the triplex system relates to specific design arrangements used in the Sydney CBD by Ausgrid

b – 15 MVA break point defined for Essential Energy (clause 14.4 and 14.5)

Based upon this description, some key features of the criteria are as follows:

- The CBD category only covers the main Sydney central business district. As such, Ausgrid is the only DNSP affected by the design planning criteria associated with this load type.
- The CBD sub-transmission network is the only portion of the network planned to an N-2 level of security. The N-2 security level does allow for customer interruptions, while network switching occurs. However, no interruption is permitted for the N-1 security level. No load at risk is permitted for either the N-2 or N-1 security levels.
- The urban network and the CBD distribution network are all designed to achieve an N-1 security level. Other than for CBD distribution feeders, the criteria allow customers to be interrupted while switching occurs. Furthermore, for sub-transmission overhead lines and zone substations some load at risk is permitted.
- The non-urban (or rural) network is generally planned to have an N security level (i.e. a radial type of supply). The exception here is sub-transmission substations supplying rural areas, which are planned to an N-1 security level.
- There are some differences in the treatment of overhead and underground sub-transmission lines, and sub-transmission and zone substations.
- There are also some criteria that define the maximum loading of urban distribution feeders under normal conditions. These criteria appear to relate to ensuring sufficient spare capacity across a group of feeders to cover N-1 situations.

Although it has not been a focus of this review, some differences in the application of these criteria by the DNSPs have been found. This is most notable with regard to the following:

- The 15 MVA limit that is used to define when Essential should use a single transformer in its non-urban zone substations. We understand that Essential applies a 5 MVA limit internally, as it considers that this is the optimal point when a two-transformer arrangement is economical.
- Endeavour applies the current 1% load at risk criteria applicable to sub-transmission overhead lines and zone substations to its *firm* ratings. In effect, additional capacity available through its *emergency* ratings are available to limit the possibility that load will need to be shed should an outage occur at the peak demand time. On the other hand, Ausgrid applies the same load at risk criteria to its *emergency* ratings; therefore, this is load that is at risk of shedding should the outage occur at the peak demand time. Ausgrid's application is more in line with how we are assuming the load at risk criteria will be applied in this report.

4.3 Schedule 2 – reliability standards

The standards associated with Schedule 2 are defined in terms of typical industry reliability metrics, namely:

- SAIDI (system average interruption duration index) – which reflects the average total duration (in minutes) over a year that any customer would be without supply
- SAIFI (system average interruption frequency index) - which reflects the average number of supply interruptions that a customer will have in a year.

Individual standards are defined for the distribution feeder types, namely CBD[4], urban, short rural and long rural. Similar to the categorisation associated with Schedule 1, this is required to distinguish the broad performance requirements and costs associated with the density of demand (or customers) in each load type.

The standards are set to reflect interruptions that have not been planned by the DNSP. In addition to its own planned interruptions, the licence conditions also define other events that should be excluded from the calculation of the above metrics. These events broadly cover the following:

- short (or momentary) interruptions with a duration of one minute or less
- interruptions due to other industry parties, of which the DNSP would have no control e.g. the transmission network, generators, emergency management bodies, customers own electrical installation.
- interruptions occurring on days where a significant event (e.g. major storm) has resulted in a very high number of interruptions (also called a major event day)[5].

Although excluding major event days should reduce the variability in the reported reliability, there still will be some variability due to external events (e.g. the severity of the weather in that year). The standards do not provide any prescription of what confidence the DNSP should have in complying with these standards to account for this variability.

For the purposes of this study, the existing standards are as follows:

Feeder type	SAIDI			SAIFI		
	Ausgrid	Endeavour	Essential	Ausgrid	Endeavour	Essential
CBD	45	na	na	0.3	na	na
Urban	80	80	125	1.2	1.2	1.8
Short rural	300	300	300	3.2	2.8	3.0
Long rural	700	na	700	6	na	4.5

4.4 Schedule 3 – individual feeder standards

Similar to Schedule 2, the standards associated with Schedule 3 are defined in terms of SAIDI and SAIFI, and the four feeder types. The difference here is that these minimum

[4] The CBD feeder type only covers the Sydney central business district, similar to the CBD load type of Schedule 1. As such, Ausgrid is the only DNSP with feeders classified as CBD.

[5] Major event days can contribute a large amount of SAIDI or SAIFI in any years. As such, SAIDI and SAIFI inclusive of these days can be quite variable, depending on the number of major events that occurred over the measure period.

standards apply to each individual feeder in that feeder type, rather than the average across all feeders[6].

The existing standards are as follows:

Feeder type	SAIDI			SAIFI		
	Ausgrid	Endeavour	Essential	Ausgrid	Endeavour	Essential
CBD	100	na	na	1.4	na	na
Urban	350	350	400	4	4	6
Short rural	1000	1000	1000	8	8	8
Long rural	1400	1400	1400	10	10	10

[6] It is worth noting that these standards apply at the feeder level. Individual customers on a feeder may receive poorer or better reliability than the feeder as a whole.

5 Development of scenarios

5.1 Introduction

This section sets out the proposed changes to the existing licence conditions to achieve the four reliability outcomes.

The changes are defined in terms of four scenarios. The first three scenarios, Scenario 1 to Scenario 3, represent a lowering of the existing reliability/security of supply standards, with Scenario 1 intending to result in the most modest reduction and Scenario 3 the greatest reduction. Scenario 4 represents the improved reliability/security outcome.

As noted in the methodology section, the specific changes have resulted from our deliberations, but we have also relied upon comments and advice from the DNSPs, AEMC and the DNSP secondments.

The specific changes for these four scenarios and our reasoning for these changes are discussed separately below in terms of the three schedules within the licence conditions.

5.2 Schedule 1 changes

There are a large number of parameters associated with Schedule 1 that could be adjusted or introduced to achieve a change in reliability. To some degree however, this study was constrained by the time available to the DNSPs to produce the forecasts. Furthermore, the possible changes we can consider are constrained by the existing licence conditions, which our scenarios must broadly follow.

For the three reliability-reduction scenarios, we have adjusted the load at risk criteria as the primary mechanism to achieve changes – mainly via the deferral of projects. We have also proposed a number of other alterations to the licence conditions that are aimed at removing or reducing the influence of some criteria that could lead to inefficient investment or design.

To ease the burden on producing the reliability-improvement scenario, we have not attempted to redefine the existing criteria. Instead, we have kept them as already defined; however, we have required that compliance to these criteria must be measured to a more onerous demand forecast. In effect, this should leave design considerations largely unchanged; however, it would tend to advance the time when non-compliance would occur.

The following provides a more detailed discussion of the specific changes we have proposed for each scenario.

5.2.1 Reliability reduction scenarios

To achieve the three reliability-reduction scenarios, we have considered a range of options covering the specific planning criteria and the categorisation. Our deliberations on this have lead to the following options as the most plausible candidates for change.

- Worst case security level

  Changing the worst-case security level would be a relatively course parameter to adjust. It only allows discrete changes (e.g. changing from N-2 to N-1), and as such, large changes in the timings of network developments may occur. As noted above, we may expect a significant change in reliability if we move from N-1 to N, but it is not so clear if such a significant change will occur if we move from N-2 to N-1 (this may depend on the level of load for N-2 load groups). We would not expect a great improvement in reliability if we moved from N-2 to N-3.

  The worst-case security levels in the existing licence conditions generally reflect practices elsewhere (nationally and internationally) for the defined load types. Therefore, we have not changed these levels in the scenarios, other than the CBD area where we have allowed for a reduction from N-2 to N-1 in the most extreme option (Scenario 3).

- Load at risk (associated with the N-1 and N-2 security levels)

  Allowing for load at risk should be a far less course parameter to adjust than the security level. This type of change can be viewed as adjusting the confidence level that the existing security criteria will be met – rather than a change to the existing security level.

  In our view, allowing for load at risk is probably where we would expect some of the most significant reductions in expenditure for very little worsening of reliability. For example, it is our understanding that the Victorian probabilistic approach has found the optimum augmentation timing to be significantly deferred from the strict N-1 time. This deferment could be quite long for low growth rates.

  NSW load duration curves, provided during our deliberations on the changes, indicated that an allowance for a short time at risk (e.g. less than 2% of time or 7 days in a year) could defer augmentations by up to 10 to 15 years (assuming annual growth rates around 2%) from the time required if no load at risk was permitted. The benefits of this deferment in avoided capital cost would appear to be at the expense of only small increases in expected energy not served.

  Therefore, we have allowed for gradually increasing levels of load at risk across the CBD and urban load types.

- Load at risk (N security level)

  The load at risk at the N security level it is set to provide a margin to reduce the likelihood that the normal rating is exceeded under normal operation[7].

  As we understand it, the requirement that capacity for sub-transmission elements and zone substations is sufficient to meet 115% of forecast demand is to ensure that sufficient capacity is available for more extreme years than the 50% PoE maximum demand forecast that the licence conditions are based upon. In our view, some increased allowance is reasonable as one in every two years you would expect actual peak demand to be above the 50% PoE level i.e. it would not seem reasonable to expect that load would need to be shed under normal conditions one in every two years. That said, the basis for the 115% is not clear and may overstate the risks of demand exceeding the rating. Therefore, in Scenario 1 and Scenario 2, we have indicated that the required capacity should be set at the 10% PoE (i.e. load would only need to be shed one in every 10 years) and capped at 115%. In Scenario 3, we have relaxed this further to say that capacity need only be sufficient for the 50% PoE conditions.

  The other N requirement concerns urban distribution feeders. This requires expected demand to be no more than 80% of feeder rating by 2014 and 75% by 2019. As we understand it, this requirement is to ensure that sufficient capacity is available to allow for the N-1 conditions. This requirement appears to be forcing DNSPs to ensure capacity is available by defining the number of alternative feeders that must be used. As such, it is driving the design of the network – possibly inefficiently. In our view, although an N-1 security level could be set for urban distribution feeders, it should be left to the DNSP to determine what the optimal arrangements should be to achieve this in any particular circumstance. As such, we do not see a need for criteria of this form to be defined in the licence conditions. Therefore, we have removed the 75% (2019) requirement for Scenario 1, and removed the requirement altogether for Scenario 2 and Scenario 3.

- Urban/non urban 10 MVA break point for the N-1 security level

  The existing licence conditions use a 10 MVA (15 MVA for Essential) maximum demand break point to define when an N-1 security level is required – below this, a radial (N security level) design is allowed. This breakpoint can have a significant effect on the number of lines and substations requiring N-1 security. This in turn can affect the design of new substations in terms of how many transformers and lines need to be included, or at least allowed for in the future. By increasing the break point (e.g. moving it to 15 MVA), you increase the number of substations that can be of a single transformer design and have radial supply.

  This break point applies to sub-transmission lines and zone substations. However, the break point is not used for urban/non urban sub-transmission substations, which are not permitted to be of a radial design.

[7] The use of the load at risk parameters here is the opposite of the use for N-2 and N-1 security levels, which provide for a margin to allow the N-1 rating to be exceeded under normal conditions.

We have proposed two changes associated with this breakpoint. Both changes only affect Scenario 2 and Scenario 3.

The first change permits sub-transmission substations with a maximum demand below the break point to be a radial design. This change has been applied to Scenario 2 and Scenario 3. We understand that the existing requirements reflect the greater importance given to sub-transmission substations, which may supply a number of zone substations. As such, an outage of this type of substation could interrupt supplies over a wide area. However, we believe the demand level is likely to be more reflective of the reliability outcome, and therefore, a change that imposes similar design criteria across the sub-transmission network elements, based upon their maximum demand level, may be appropriate.

The second change concerns increasing the break point to permit a greater percentage of sub-transmission network elements to be a radial design. This change was suggested by a number of DNSPs. We consider it less likely that the specific cost reductions associated with this change would be justified by the increases in the expected unserved energy. Nonetheless, to allow this change to be assessed by the DNSPs, we increased the break point for Scenario 2 and Scenario 3 to 15 MVA and 20 MVA respectively.

- N-2 and N-1 customer restoration durations

  Existing restoration durations defined within the licence conditions cover:

  - nil – meaning no customer's load should be lost for that credible contingency
  - <1 minute – implying some form of automatic system will be required to restore the load
  - <1 hour – implying remote operations of the switchgear (i.e. from the control room) will be required to restore load (this requires the relevant SCADA to the switchgear, and so is more common on sub-transmission (including zone substation) network types)
  - < 4hours – implying manual operation of switches to restore load, which would allow about four switching operations (i.e. load could be transferred via four locations).

  We would expect that allowing load to be restored following a contingency would reduce the amount of spare capacity required in the network. Furthermore, as more time is permitted to restore customers, restorations that are more complicated can be achieved (e.g. the distribution network can be used to back-up the sub-transmission network). The additional capacity available via the extra time for restoration can both defer the time when a major augmentation may be required and reduce switchgear and control requirements (although the reduction in switchgear and control may be offset by operating expenses through manual restorations).

For example, for sub-transmission and zone substations in the CBD load type, the existing requirements appear to limit the possibility of restoring load due to transfers via the distribution network. The increased restoration times should allow some support from the distribution system. This may defer the need for major sub-transmission upgrades by up to 5 years for a small increase in expected energy not served.

We considered that this was a suitable parameter to change in this scenario. Originally, in submission to the AEMC, some of the DNSPs appear to have viewed this as a credible option also. However, in commentary during the course of this study, the DNSPs considered that this was unlikely to achieve a significant reduction in capex and provided some explanatory material to support this view. There was also some concern that it may be too time-consuming for the DNSPs to assess this and the other proposed changes in the short period of time available for this review. As such, the AEMC instructed us not to include a change associated with this parameter.

5.2.2 Reliability improvement scenario

We sought to define a relatively simple change for this scenario. In this regard, the outcome is achieved by using the 10% PoE forecast maximum demand conditions rather than the 50% PoE conditions. This should not change the design of the network to any great degree; however, it would reduce actual levels of allowed load at risk, essentially advancing the timing of augmentations. As such, this was thought to be a relatively simple option for the DNSPs to assess the cost and reliability impacts.

5.2.3 Summary of changes

The tables below summarise the specific changes associated with each scenario in comparison to the existing licence conditions. To aid in their appreciation, we have set these out in terms of the three load categories: CBD, urban and non-urban.

Table 1 Schedule 1 changes – CBD load type

Network type	Licence condition change type	Existing	Scenario 1 (modest)	Scenario 2 (large)	Scenario 3 (extreme)	Scenario 4 (improve)
Sub-transmission (including zone substations)	Worst case security level	N-2	No change	No change	N-1	No change
	N-2 load at risk	None	0.5% of time or no greater than 40 MVA of forecast demand	1% of time or no greater than 50 MVA of forecast demand	Not applicable	No change
Distribution feeders and substations	N-1 load at risk	None	0.5% of time (no forecast demand limit)	1% of time (no forecast demand limit)	2% of time (no forecast demand limit)	No change
All network types	forecast demand definition	50% PoE peak demand forecast	No change	No change	No change	10% PoE peak demand forecast

Table 2 Schedule 1 changes – urban load type

Network type	Licence condition change type	Existing	Scenario 1 (modest)	Scenario 2 (large)	Scenario 3 (extreme)	Scenario 4 (improve)
Sub-transmission substations and UG lines	N-1 load at risk	None	0.5% of time or no greater than 40 MVA of forecast demand	1.5% of time or no greater than 50 MVA of forecast demand	2% of time (no forecast demand limit)	No change
Sub-transmission OH lines and zone substations	N-1 load at risk	1% time or 20% above thermal capacity	No change	1.5% of time or no greater than 50 MVA of forecast demand	2% of time (no forecast demand limit)	No change
Sub-transmission substations, OH and UG lines and zone substations	N load at risk	Thermal capacity at 115% of forecast demand	Thermal capacity to meet 10% PoE forecast peak demand, but capped at 115% of the 50% PoE maximum demand	Thermal capacity to meet 10% PoE forecast peak demand, but capped at 115% of the 50% PoE maximum demand	Thermal capacity at 100% of forecast demand	No change
	Categorisation defining when the N-1 security level is	10 MVA break point for sub-transmission lines	No change	15 MVA (for all asset types)	20 MVA (for all asset types)	No change

Network type	Licence condition change type	Existing	Scenario 1 (modest)	Scenario 2 (large)	Scenario 3 (extreme)	Scenario 4 (improve)
	applicable for urban and non-urban sub-transmission and zone substation network types	and zone substations (15 MVA break point for Essential Energy). Sub-transmission substations are all N-1		No distinction for Essential Energy	No distinction for Essential Energy	
Distribution feeders	N-1 load at risk	None	0.5% of time (no forecast demand limit)	1% of time (no forecast demand limit)	2% of time (no forecast demand limit)	No change
	N load at risk (footnote 4)	Expected demand no more than 80% (2014) and 75% (2019)	Remove 75% for 2019	Remove clause	Remove clause	No change
All network types	forecast demand definition	50% PoE peak demand forecast	No change	No change	No change	10% PoE peak demand forecast

Table 3 Schedule 1 changes – non-urban load type

Network type	Licence condition change type	Existing	Scenario 1 (modest)	Scenario 2 (large)	Scenario 3 (extreme)	Scenario 4 (improve)
Sub-transmission substations	Security level for sub-transmission substations	N-1 for all sub-transmission substations	No change	Sub-transmission substations with demand below urban break-point given N security level	Sub-transmission substations with demand below urban break-point given N security level	No change
All sub-transmission and zone substation	N load at risk	Thermal capacity at 115% of forecast demand	Thermal capacity to meet 10% PoE forecast peak demand, but capped at 115% of the 50% PoE maximum demand	Thermal capacity to meet 10% PoE forecast peak demand, but capped at 115% of the 50% PoE maximum demand	Thermal capacity at 100% of forecast demand	No change
All network types	forecast demand definition	50% PoE peak demand forecast	No change	No change	No change	10% PoE peak demand forecast

5.3 Schedule 2 changes

Three main parameters could be changed to affect capex and reliability associated with the standards in Schedule 2. These are:

- changing the standard
- changing how reliability should be calculated to assess non-compliance
- changing the categories.

We rejected the option of changing the categorisation as we considered that this would be difficult for us to define without detailed analysis and discussions with the DNSPs. We were also concerned that this may place the categorisation out of step with classifications used by the AER for its service incentive scheme.

With regard to the first two options, we considered that these could be viewed as essentially the same issue. The setting of the standard should reflect the methodology used to calculate reliability. As noted in the previous section, reliability can vary from year to year due to uncontrollable factors related to environmental conditions (e.g. number and extremeness of storms). Therefore, the DNSP cannot be completely certain it will comply with the standards; it can only have a level of confidence in complying.

Therefore, we considered that a simple approach was to maintain the standards and the methodology to calculate reliability (e.g. excluded events), but to define the confidence level that the DNSP should plan to. Defining confidence levels would reduce the burden of compliance.

Table 4 provides the confidence levels associated with each scenario. In our view, the confidence levels associated with the reliability-reduction scenarios should result in a significant relaxation of the obligations on the DNSPs without a major reduction in average reliability. For example, even in the more extreme scenarios (Scenario 2 and Scenario 3), reliability should only be worse than the standard one in every two years.

Table 4 – Schedule 2 – scenario changes

Change	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Confidence not exceeded	75%	50%	50%	99%

5.4 Schedule 3 changes

The options available to change Schedule 3 are similar to Schedule 2. However, the use of the confidence limit is not appropriate, as there is unlikely to be the available data to assess this accurately. As such, for Schedule 3, the adjustment of the standard is more appropriate.

Additionally, we also considered that a cap should be placed on the number of projects to be undertaken in each year to address feeders that are non-compliant with Schedule 3.

This change was aimed at those DNSPs (most notably Essential) that were still expecting to have significant levels of their network non-compliant in the future.

Our view was that, for those DNSPs that have a large number of feeders still exceeding the existing standards, the cap would limit the level of expenditure incurred each year – effectively stretching out compliance expenditure over a longer period.

Table 5 provides the changes associated with each scenario.

Table 5 – Schedule 3 – scenario changes

Change	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Percentage increase in standards	No change	10%	20%	-10%
Limit (as percentage of the total number of feeders)	4%	2%	1%	10%

6 Overview of the DNSP capex and reliability forecasts

This section provides an overview of the expenditure and reliability forecasts provided by the DNSPs. The section summarises the expenditure and reliability changes associated with each scenario, and the contribution of the various schedules to these changes.

The aim of this section is to introduce the forecasts, indicating which schedules are most material to the DNSPs in terms of the effects that changes to the licence conditions may have on future expenditure and reliability. This understanding is important in appreciating the materiality of the sections that follow, which discuss the methodologies employed by the DNSPs to prepare the forecasts.

The results presented are based upon the summation of forecasts across the 15-year study period, commencing in the next regulatory period. The results do not include any capex or reliability associated with the current period.

In appreciating the results and discussion presented here, it is important to note that reliability is discussed in terms of expected energy not served (defined as EENS in charts) – not other reliability metrics such as SAIDI or SAIFI. Furthermore, a negative change in capex or reliability means a decrease in capex or expected energy not served from the base case. As such, a negative change in capex (a capex reduction) is generally associated with a positive change in reliability (a reliability-reduction due to the increase in expected energy not served) and vice versa.

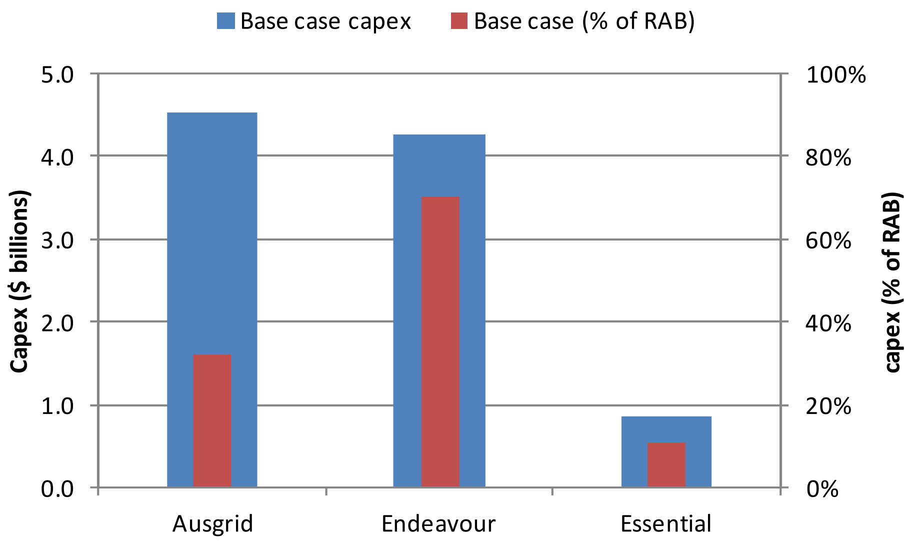
6.1 Base case comparison

It is useful to compare first the base case forecast capex of each DNSP (i.e. the forecast assuming the continuation of the existing licence conditions). These forecasts indicate future levels of expenditure over the study period, suggesting the scale of changes that could be achievable.

Figure 1 shows a chart of the total base case capex over the 15-year study period. To show the relative scale of this capex, it is also shown as a proportion of the regulated asset base (RAB)[8] (on the secondary axis).

[8] The RAB is the forecast closing RAB in 2013/14, taken from the last AER determination.

Figure 1 – base case capex comparison



This indicates that Ausgrid and Endeavour are forecasting a similar base case; however, Endeavour is far greater as a percentage of its RAB. Essential is by far the lowest, in both scale and as a proportion of its RAB. As will be discussed in the next section, the low level of capex in the base case of Essential, appears to be partly due to it anticipating almost no developments associated with its sub-transmission network over the 15-year study period.

This suggests that the potential gains (in terms of reduced capex or prices) that could be achieved through changes to the licence conditions may be far less significant for Essential. On the other hand, Endeavour shows the potential for significant gains over the study period.

All that said, care is need in comparing the base cases between DNSPs, due to the different approaches used when allowing for capex associated with intrinsic load growth (which is generally sensitive to the licence conditions), and capex associated with new development and replacements (which is generally far less sensitive to the licence conditions). For example, both Ausgrid and Endeavour included in their base case large portions of capex associated with new development and replacements. However, it appears that Essential only included capex associated with intrinsic load growth.

6.2 Scenario capex and reliability changes

Figure 2 and Figure 3 show the total change (from the base case) in capex and reliability over the 15-year study period as forecast by the DNSPs for the four scenarios.

Figure 2 – total capex change by scenario

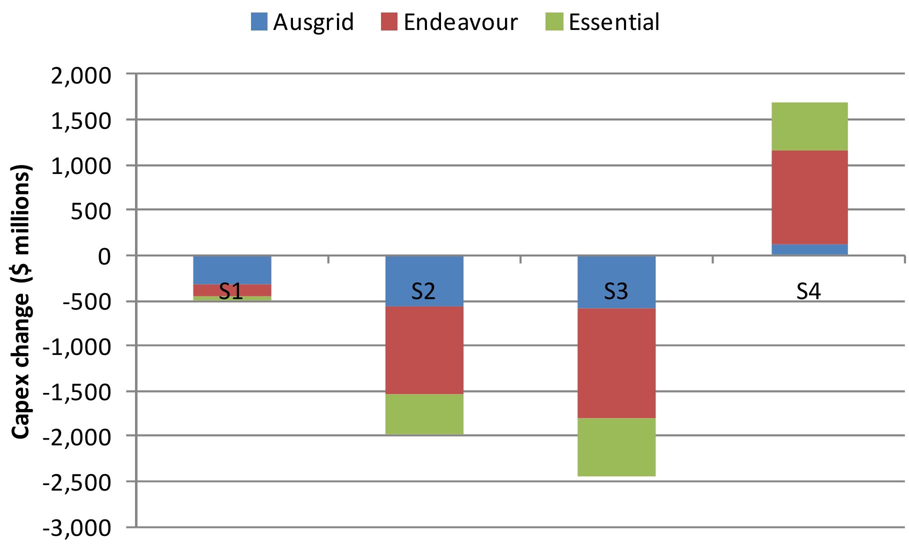
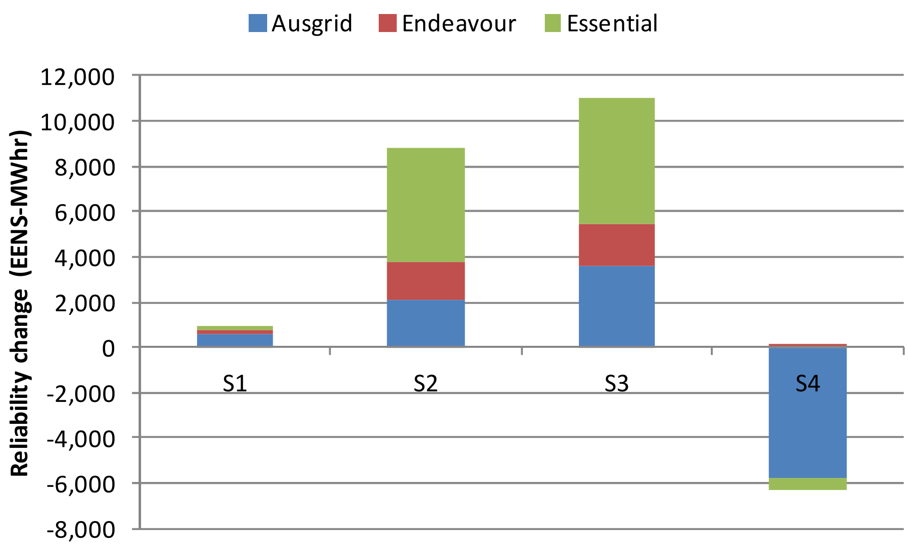


Figure 3 – total reliability change by scenario



For the three reliability-reduction scenarios, the following points are worth noting:

- Capex changes
  - The total capex reduction across all three DNSPs will range between $0.5 billion and nearly $2.5 billion.
  - There also appears to be a significant step in the change between Scenario 1 and Scenario 2, where the capex reduction increases significantly between these two scenarios, with a more modest reduction between Scenario 2 and Scenario 3.
  - With regard to the relative proportion from each DNSP, Ausgrid contributes the greatest proportion to the reduction due to Scenario 1; however, this major

contribution changes to Endeavour (and Essential to a lesser degree) for Scenario 2 and Scenario 3.

- Reliability changes
  - This capex pattern is matched by the corresponding reduction in reliability, where there also appears to be a step change between Scenario 1 and Scenario 2; however, in this case, the reduction in reliability between these two scenarios is more pronounced, with a total expected energy not served of around 1 GWhr for Scenario 1, increasing to almost 9 GWhr for Scenario 2, and a more modest increase to around 11 GWhr for Scenario 3.
  - The contribution from Essential becomes far more pronounced in Scenario 2 and Scenario 3. As will be discussed later, this effect is due to the Schedule 3 changes in these two scenarios beginning to deteriorate reliability significantly for Essential.

For the reliability-improvement scenario, the capex increase across all three DNSPs is just over $1.5 billion, with Essential and Endeavour contributing most to the increase. The relative improvement in reliability is fairly large, reducing the expected energy not served by approximately 7 GWhr. However, the majority of this improvement relates to Ausgrid.

To appreciate better the relative scale of these changes, Figure 4 and Figure 5 show similar figures as a percentage of the base case. These charts suggest that all DNSPs are forecasting small gains associated with Scenario 1. Ausgrid is only predicting modest gains across all the reliability-reduction scenarios. Essential on the other hand is predicting fairly major gains in Scenario 2 and Scenario 3. These findings are in line with the comments above concerning the relative scales of the base cases.

The reliability changes follow a slightly different pattern. However, we believe care is required in comparing this metric, as we believe that the DNSPs may have made different assumptions in reporting base case reliability.

For the reliability-improvement scenario, the capex changes are considerably different, but in similar proportions to the other scenarios. Ausgrid is forecasting a significant reduction in unserved energy associated with this scenario, whereas the reduction forecast by Essential is far more modest. The reliability results for Endeavour are anomalous, with Endeavour appearing to forecast a small increase in unserved energy due to this scenario. We believe that this is due to the methodology it has used to calculate expected energy not served for Schedule 1 in this scenario (this issue is discussed further in Section 8.2.4.2).

Figure 4 - total capex change as percentage of base case

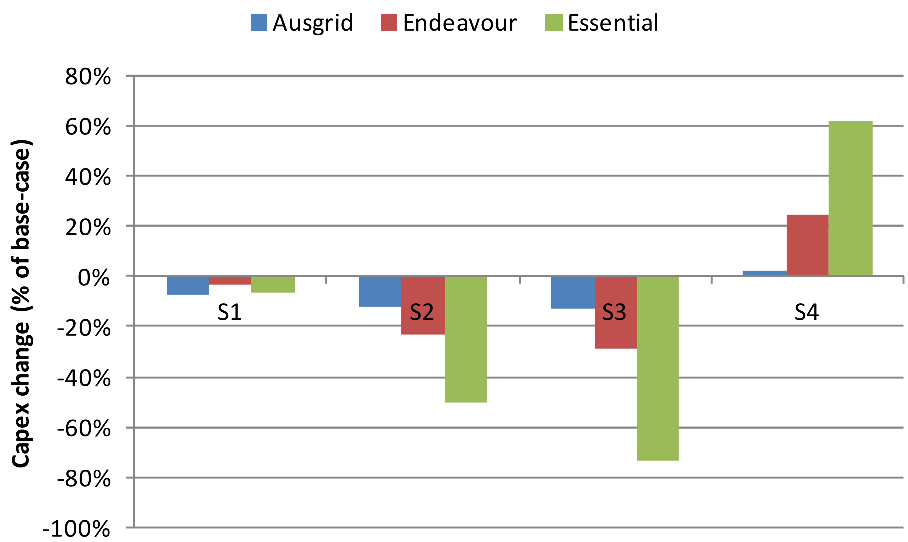
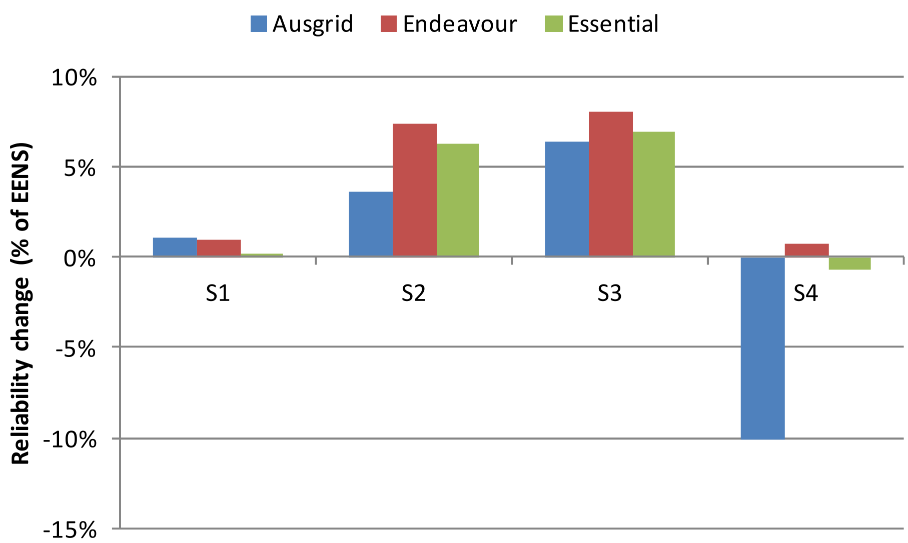


Figure 5 - total reliability change as percentage of base case



As the three DNSP networks are of different scales, we have also assessed the capex and reliability changes as a proportion of the RAB and the energy consumption[9] of the network. This provides a useful metric to compare the scale of the forecast changes between DNSPs. Figure 6 and Figure 7 show the total change in capex and reliability, in terms of these metrics, over the 15-year study period.

[9] The energy consumption in 2009/10 is used based upon the actual figure in that year provided in the AER 2009/10 performance report.

Figure 6 – total capex change as percentage of RAB

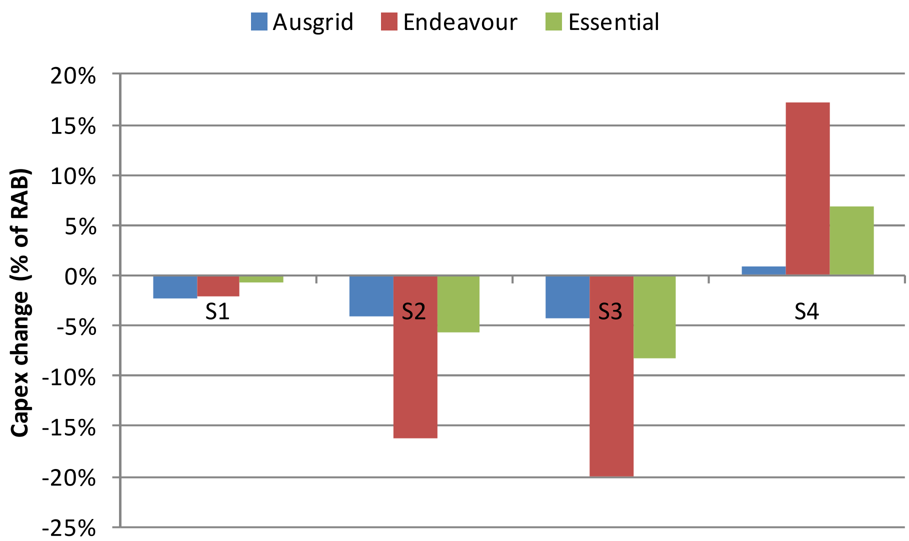
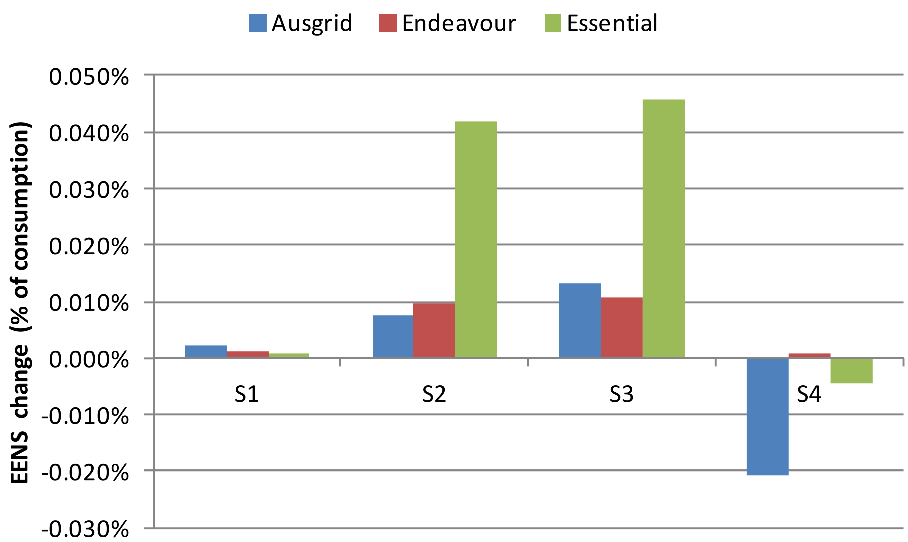


Figure 7 – total reliability change as percentage of energy consumption



For the three reliability-reduction scenarios, the following are worth noting:

- Capex changes
  - For Scenario 1, Ausgrid has the greatest reduction in capex, although this is only 2% of its RAB. Essential has the lowest reduction, at 1% of its RAB.
  - For Scenario 2 and Scenario 3, the Ausgrid position reverses, with still only a modest reduction of only 4%. Whereas, Endeavour's capex reduction increases significantly to 16% and 20% respectively, which is four to five times the Ausgrid amount. Essential is at a similar proportion to Ausgrid for Scenario 2, at 6%, with a further increase for Scenario 3 to 8%, which is double the Ausgrid amount.

- Reliability changes
  - Essential and Endeavour have similar reliability changes for Scenario 1, both at 0.001% of consumption. Ausgrid is approximately twice as worse at 0.002%.
  - For Scenario 2, Ausgrid and Endeavour are also at similar levels of around 0.01%. Essential on the other hand has increased considerably to 0.04%.
  - For Scenario 3, all DNSPs increase slightly from their Scenario 2 levels, with Ausgrid showing the most pronounced increase, overtaking Endeavour.

For the reliability-improvement scenario, the capex changes are considerably different, with Ausgrid at only 1% but Endeavour at 17% of its RAB. Conversely, Ausgrid is forecasting a significant reliability improvement of 0.021%, whereas Essential is forecasting a reliability improvement of 0.005%. As noted above, the reliability results for Endeavour are anomalous.

6.3 Scenarios and changes to the licence conditions

Table 6 and Table 7 provide a more detailed breakdown of the capex and reliability changes associated with each scenario. These tables indicate which components of the three schedules are contributing to the overall change and the proportion from each DNSP.

These results indicate that the changes to Schedule 1 are by far the most significant driver of changes to capex across all scenarios, particularly Scenarios 1 and 2. Only in the case of Essential is another schedule, Schedule 3, contributing significantly to the capex reduction. This is most notable in Scenarios 2, 3 and 4.

For the change in reliability, the relationship to Schedule 1 is not so pronounced. The reliability change associated with Schedule 1 is still the most significant for Scenario 1. However, for the two more extreme reliability reduction scenarios, Scenario 2 and Scenario 3, Schedule 3 contributes the most significantly. The change here is predominantly driven by Essential, and relates to the effect that the introduction of the cap on the number of non-compliant feeders addressed each year has had on Essential (see the further discussion on this issue in Section 8.3).

For Scenario 4, Schedule 1 is the least significant on the change in reliability - although, care is required in interpreting these results as there are some issues with the DNSPs forecasts for this scenario and schedule. By far the most significant contributor is Schedule 2. However, this change is predominately driven by Ausgrid. Schedule 3 is also driving changes more evenly distributed across the three DNSPs. Schedule 3 contributes more significantly, particularly for Essential and Ausgrid. For Essential, this reflects the greater significance of Schedule 3 on its capex.

A more detailed discussion of the contributions of the changes to the schedules on each scenario follows.

Table 6 – capex change by scenario and schedule

		Scenario 1				Scenario 2				Scenario 3				Scenario 4			
			proportion				proportion				proportion				proportion		
		Capex ($ million)	Ausgrid	Endeavour	Essential	Capex ($ million)	Ausgrid	Endeavour	Essential	Capex ($ million)	Ausgrid	Endeavour	Essential	Capex ($ million)	Ausgrid	Endeavour	Essential
Schedule 1 - design planning criteria																	
Load type	*Network type*																
CBD	Sub-transmission	-210.6	100%	-	-	-243.0	100%	-	-	-245.1	100%	-	-	43.2	100%	-	-
	Distribution	-1.9	100%	-	-	-8.5	100%	-	-	-10.8	100%	-	-	8.9	100%	-	-
Urban	Sub-transmission	-123.3	45%	55%	-	-1,072.0	17%	83%	-	-1,281.0	15%	85%	-	891.5	-9%	109%	-
	Distribution	-146.2	32%	41%	27%	-262.4	43%	35%	22%	-284.0	44%	34%	23%	68.3	100%	-	-
Non-Urban	Sub-transmission	-	-	-	-	-	-	-	-	-13.5	-	-	100%	-	-	-	-
	Sub total	**-482.0**	65%	27%	8%	**-1,585.8**	35%	62%	4%	**-1,834.4**	31%	65%	4%	**1,011.8**	4%	96%	-
Schedule 2 - reliability standards																	
	Feeder type																
	CBD	-.3	100%	-	-	-.2	100%	-	-	1.4	100%	-	-	-.3	100%	-	-
	Urban	-	-	-	-	-	-	-	-	-	-	-	-	36.0	97%	-	3%
	Short Rural	-3.2	100%	-	-	-3.2	100%	-	-	-3.2	100%	-	-	33.9	87%	-	13%
	Long Rural	-.2	100%	-	-	-.2	100%	-	-	-.2	100%	-	-	1.2	88%	-	12%
	Sub total	**-3.8**	100%	-	-	**-3.7**	100%	-	-	**-2.1**	100%	-	-	**70.7**	92%	-	8%
Schedule 3 - individual feeder standards																	
	Feeder type																
	CBD	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Urban	-2.3	-	-	100%	-48.8	13%	9%	77%	-92.3	13%	29%	58%	129.9	4%	57%	40%
	Short Rural	-10.8	-	-	100%	-239.4	0%	2%	98%	-361.1	0%	2%	98%	332.9	0%	2%	98%
	Long Rural	-2.0	-	-	100%	-103.8	-	-	100%	-148.4	-	-	100%	152.2	-	-	100%
	Sub total	**-15.0**	-	-	100%	**-392.0**	2%	2%	96%	**-601.8**	2%	5%	92%	**615.0**	1%	13%	86%
Total		**-500.8**	***63%***	***26%***	***11%***	**-1,981.5**	***28%***	***50%***	***22%***	**-2,438.3**	***24%***	***50%***	***26%***	**1,697.6**	***7%***	***62%***	***32%***

Table 7 – reliability change by scenario and schedule

		Scenario 1				Scenario 2				Scenario 3				Scenario 4			
			proportion				proportion				proportion				proportion		
		EENS (MWhr)	Ausgrid	Endeavour	Essential	EENS (MWhr)	Ausgrid	Endeavour	Essential	EENS (MWhr)	Ausgrid	Endeavour	Essential	EENS (MWhr)	Ausgrid	Endeavour	Essential
Schedule 1 - design planning criteria																	
Load type	*Network type*																
CBD	Sub-transmission		100%	-	-	6	100%	-	-	16	100%	-	-	-	-	-	-
	Distribution	2	100%	-	-	9	100%	-	-	23	100%	-	-	-	-	-	-
Urban	Sub-transmission	272	100%	0%	-	2,271	41%	59%	-	2,776	50%	50%	-	747	10%	90%	-
	Distribution	457	46%	47%	7%	827	63%	30%	7%	1,349	75%	19%	6%	-109	100%	-	-
Non-Urban	Sub-transmission	-	-	-	-	12	100%	-	-	22	52%	-	48%	-8	100%	-	-
	Sub total	**732**	66%	29%	5%	**3,125**	47%	51%	2%	**4,185**	59%	39%	2%	**631**	-7%	107%	-
Schedule 2 - reliability standards																	
	Feeder type																
	CBD	-	100%	-	-	-7	100%	-	-	-36	100%	-	-	2	100%	-	-
	Urban	-	-	-	-	-	-	-	-	-	-	-	-	-2,436	99%	-	1%
	Short Rural	94	100%	-	-	94	100%	-	-	94	100%	-	-	-2,728	96%	-	4%
	Long Rural	12	100%	-	-	12	100%	-	-	12	100%	-	-	-106	95%	-	5%
	Sub total	**106**	100%	-	-	**99**	100%	-	-	**70**	100%	-	-	**-5,268**	97%	-	3%
Schedule 3 - individual feeder standards																	
	Feeder type																
	CBD	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Urban	20	-	-	100%	924	44%	6%	50%	1,608	57%	11%	32%	-986	49%	47%	4%
	Short Rural	103	-	-	100%	2,584	4%	1%	95%	2,880	6%	1%	93%	-323	26%	10%	64%
	Long Rural	87	-	-	100%	2,070	-	-	100%	2,267	-	-	100%	-173	-	-	100%
	Sub total	**209**	-	-	100%	**5,578**	9%	2%	89%	**6,755**	16%	3%	81%	**-1,482**	38%	34%	28%
Total		**1,048**	**56%**	**20%**	**23%**	**8,802**	***24%***	***19%***	***57%***	**11,010**	***33%***	***17%***	***50%***	**-6,120**	***94%***	***-3%***	***9%***

6.3.1 Scenario 1

Schedule 1 changes

The changes due to Schedule 1 are the most significant, contributing 96% to the capex change and 70% to the reliability change.

The changes associated with Ausgrid's CBD network appear to contribute the most significantly to the capex change with very little associated reduction in reliability.

However, the significance of this result may be a little misleading. The vast majority of this change in capex is associated with the allowance for load at risk for Ausgrid's CBD sub-transmission assets; the distribution network contributes almost nothing to the change. The majority of the capex change for the CBD sub-transmission category (approximately $200 million) is associated with planned major projects at the very end of our 15-year study period; there is no change in capex in the first 5-year period, and only a small amount in the second.

Given this, the changes to design planning criteria associated with the urban network category are potentially more significant on capex and reliability in the short to medium term.

Schedule 2 changes

The changes due to Schedule 2 are the least significant, contributing only 1% to the capex change and 10% to the reliability change. All the changes in capex and reliability are due to Ausgrid, with neither Endeavour nor Essential forecasting any changes. Interestingly, the main change for Ausgrid is due to its short rural feeders.

Schedule 3 changes

The changes due to Schedule 3 are not particularly significant on capex, contributing only 3% to the overall change; however, they are more significant on reliability, contributing 20% to the overall change.

All the changes in capex and reliability are due to Essential, with neither Ausgrid nor Endeavour forecasting any changes. The main changes are associated with Essential's short rural feeders; although, the break down between feeder types for Essential should follow its existing feeder proportions due to the methodology it applied.

6.3.2 Scenario 2

Schedule 1 changes

The capex changes due to Schedule 1 are still the most significant for Scenario 2, but have reduced to 80%. The contribution to the reliability change has reduced more significantly to only 36%.

Although the contribution is lower, Scenario 2 nonetheless has a significant increase in the capex and reliability change from Scenario 1, with the capex change increasing about three-fold and the reliability change increasing four-fold.

The major portion of this change is due to the increased levels of load at risk allowed for the urban sub-transmission network. For this one category of assets, the change in capex and reliability over the study period increases nearly nine-fold from Scenario 1, with Ausgrid and Endeavour contributing similar proportions.

The urban distribution category also shows around a doubling of the capex and reliability change; although, this is still only a small percentage of the capex change (17%).

The capex and reliability changes associated with the CBD network have not changed significantly from Scenario 1. However, the points noted above about the possibly misleading nature of these results are still relevant for Scenario 2. As such, it still appears that the proposed changes to the design planning criteria associated with the CBD network would not result in significant changes to capex and reliability in the short to medium term.

Schedule 2 changes

The changes due to Schedule 2 are similar to Scenario 1, and are still the least significant, contributing effectively nothing to the capex change and only 1% to the reliability change.

All the changes in capex and reliability are still due to Ausgrid, with neither Endeavour nor Essential forecasting any changes.

Schedule 3 changes

The changes due to Schedule 3 have increased very significantly in Scenario 2 from Scenario 1. This schedule now contributes only 20% to the overall capex change and 63% to the reliability change.

The majority of this change is due to Essential, particularly from its short and long rural feeders. As noted above, the scale of the changes, particularly to reliability, is due to the introduction of the cap on the number of non-compliant feeders addressed each year. For Scenario 2, the cap begins to have a far more significant impact on the number of non-compliant feeders that need to be addressed (reducing this significantly); however, Essential is also forecasting that it will also result in an escalating number of non-compliant feeders remaining on the network, contributing to an escalating amount of expected energy not served.

Ausgrid and Endeavour are also forecasting some capex and reliability changes associated with this Scenario. However, in these cases, the changes are driven by the reduction in the standards that we have proposed; neither Ausgrid nor Endeavour considers that the cap will be sufficient to affect their forecasts for this scenario.

6.3.3 Scenario 3

Schedule 1 changes

The capex change associated with Schedule 1 in Scenario 3 shows only a modest increase from Scenario 2 (16%). The change in reliability however is more significant (34%). The contribution of Schedule 1 to the overall changes are broadly similar at 75% for the capex change and 38% for the reliability change.

The contribution by the various network types is very similar to that discussed above for Scenario 2.

Schedule 2 changes

The changes due to Schedule 2 are similar to Scenario 2 (or Scenario 1), and are still the least significant, contributing effectively nothing to the capex change and only 1% to the reliability change.

All the changes in capex and reliability are still due to Ausgrid, with neither Endeavour nor Essential forecasting any changes.

Schedule 3 changes

The capex changes due to Schedule 3 have approximately doubled from Scenario 2. This schedule now contributes 25% to the overall capex change. The reliability change has increased by a much lower amount however (20%).

The majority of this change is still due to Essential, and for the same reason discussed above (i.e. the effect of the introduction of the cap).

Ausgrid and Endeavour contribute a much lower amount, and similar to Scenario 2, these changes are driven by the reduction in the standards that we have proposed – not the cap.

6.3.4 Scenario 4

Schedule 1 changes

Due to the limitations associated with the forecasting for Scenario 4, greater care is required in interpreting the detailed breakdown. This has significantly affected the forecast associated with Schedule 1, as follows:

- Ausgrid appears to be forecasting a capex reduction for the urban sub-transmission category; however, we understand that this amount does not include an additional $142 million that Ausgrid considers would be advanced prior to 2014 for this scenario. It is not clear whether a similar issue has caused the reported increase in expected energy not served for the urban sub-transmission category, which also appears anomalous.
- Endeavour has not provided a forecast for urban distribution feeders (capex or reliability). Endeavour has also calculated the reliability change associated with sub-transmission incorrectly. This is resulting in an apparent increase in the expected energy not served from the base case, when a reduction should occur.
- Essential has not provided a forecast for any network categories (capex or reliability).

Noting the above, for Scenario 4, Schedule 1 still appears to be the most significant in terms of the capex change, contributing 60% to the overall change. This contribution may be expected to increase if the above issues are addressed.

Schedule 2 changes

Schedule 2 is by far the least significant with regard to changes to capex, contributing only 4% to the total change. The change in reliability however is far more significant, contributing 86% to the overall reliability change.

As noted above, Ausgrid contributes the majority of the capex and reliability change to this category. This appears to be due to the amount of reliability change that Ausgrid forecasts it needs to achieve the high confidence level associated with Scenario 4.

Endeavour on the other hand is already considerably better than the existing reliability standards, and as such, it considers that it would achieve this confidence level without further work.

Essential is forecasting a small amount of additional work, but at a much lower level than Ausgrid. As noted in Section 8.4, we believe that there may be an issue with Essential's reported forecast, as Essential does not appear to be carrying the reliability improvements forward. As such, Essential may be understating the overall reliability improvement. We estimate that this could result in a further reduction in expected energy not served for Essential of around 270 MWhr.

Schedule 3 changes

Schedule 3 is fairly significant on the overall capex and reliability change, contributing 36% and 24% respectively.

Essential contributes the majority of the capex change (86%), while all three DNSPs contribute more evenly to the reliability. This difference appears to be partly reflective of differences in the costs to comply compared to the reliability improvements between DNSPs (i.e. Essential is relatively more costly).

For Ausgrid, it is also due to its assumption that addressing a poor performing feeder has a significant contribution to overall reliability, which carries forward in time.

7 DNSP capex and reliability profiles

The previous section has focused on comparing total capex and reliability over the study period between DNSPs. However, to appreciate the significance of the changes through this 15-year study period it is helpful to consider the profile of the changes. For example, such a profile suggests the extent that the changes will affect forthcoming regulatory periods.

To assess this effect, we have considered the DNSPs separately. The analysis considers the year-by-year changes to capex and reliability. Annual capex (and to a lesser degree reliability) can be variable, due to the "lumpy" nature of investment, particularly at the sub-transmission level. Therefore, to smooth out the annual changes we have also graphed the total changes in the three 5-year regulatory periods within the study period (these are termed RP1, RP2 and RP3 in the graphs and discussion provided).

This section uses similar conventions when discussing capex and reliability changes as noted in the introduction to Section 6.

7.1 Ausgrid capex and reliability profile

7.1.1 Base case

Figure 8 shows the base case capex through the study period associated with each of the three schedules. This clearly indicates that Schedule 1 is by far the most significant driver of capex throughout the period. Given this, Figure 9 shows a further breakdown of Schedule 1 by network type.

Figure 8 – Ausgrid base case capex (contribution by schedule)

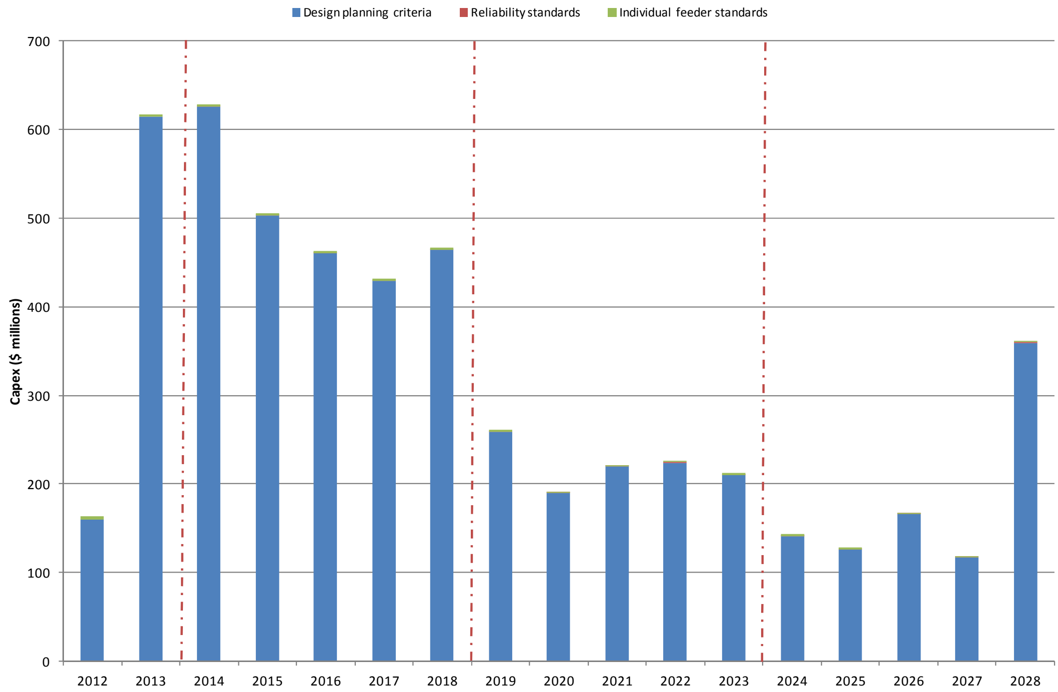
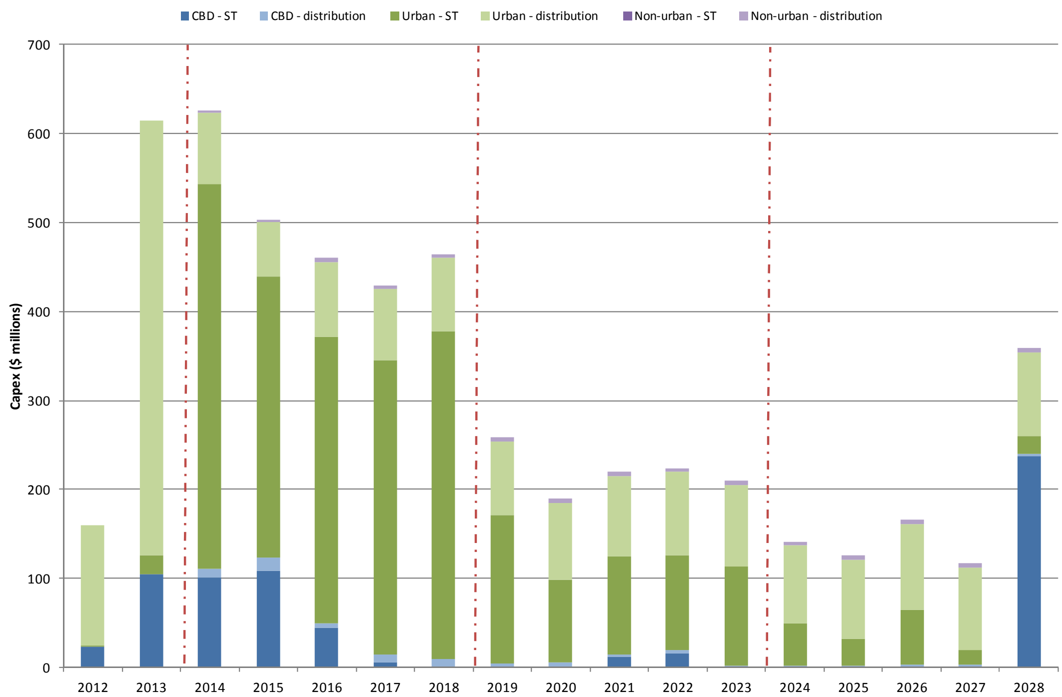


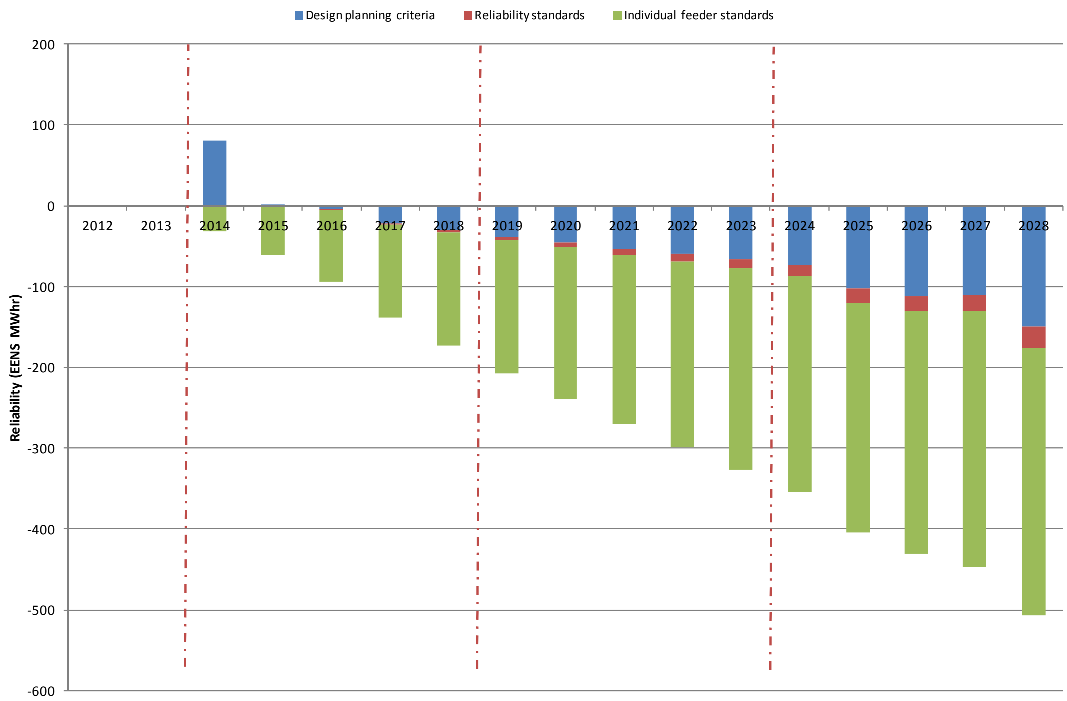
Figure 9 – Ausgrid base case capex – Schedule 1



The two figures show capex will be at relatively high levels in the RP1, due to both CBD and urban sub-transmission developments. This capex level reduces however in RP2 and RP3. The capex in the last year of the study period increases significantly, due to some large projects associated with the CBD sub-transmission developments.

Figure 10 shows the base case reliability through the study period associated with each of the three schedules. This graph indicates that expected energy not served is expected to reduce during the study period, with works to comply with Schedule 3 contributing most significantly to the reduction.

Figure 10 – Ausgrid base case reliability (contribution by schedule)



7.1.2 Scenarios

Figure 11 and Figure 12 show the profile of the capex change forecast by Ausgrid. The year-by-year profile is very lumpy, with capex reduction and increases occurring in different years for all scenarios. This variability is a consequence of Ausgrid's base case forecast, which at the sub-transmission level is developed from a set of individual projects. As such, the base-case forecast is quite variable year-to-year. As these projects are advanced or deferred, due to the scenario, the capex change in each year is also very variable. The smoothed chart however is more in accordance with our expectation of the effect that the scenarios should have on capex.

Interestingly, the charts indicate that a significant portion of the capex change (approximately $200 million) is due to a capex change in the last year of the study period. As noted above, this project is associated with Ausgrid's CBD network, and is related to Schedule 1 of the licence conditions. The three reliability-reduction scenarios defer this capex outside of the study period. If these costs are excluded then the capex changes associated with these three scenarios is far less significant than suggested by the analysis in the previous section.

The reliability-improvement scenario on the other hand shows a significant increase in the first year of the study period. We understand that this is due to the capex that is required to comply with the improved reliability standards associated with the changes to Schedule 2. In reality, we would expect that there would be some transitional arrangements associated with such an improvement, as such it may be expected that this increase would be allowed to occur at least over the first 5-year period.

Figure 11 – Ausgrid profile of capex change

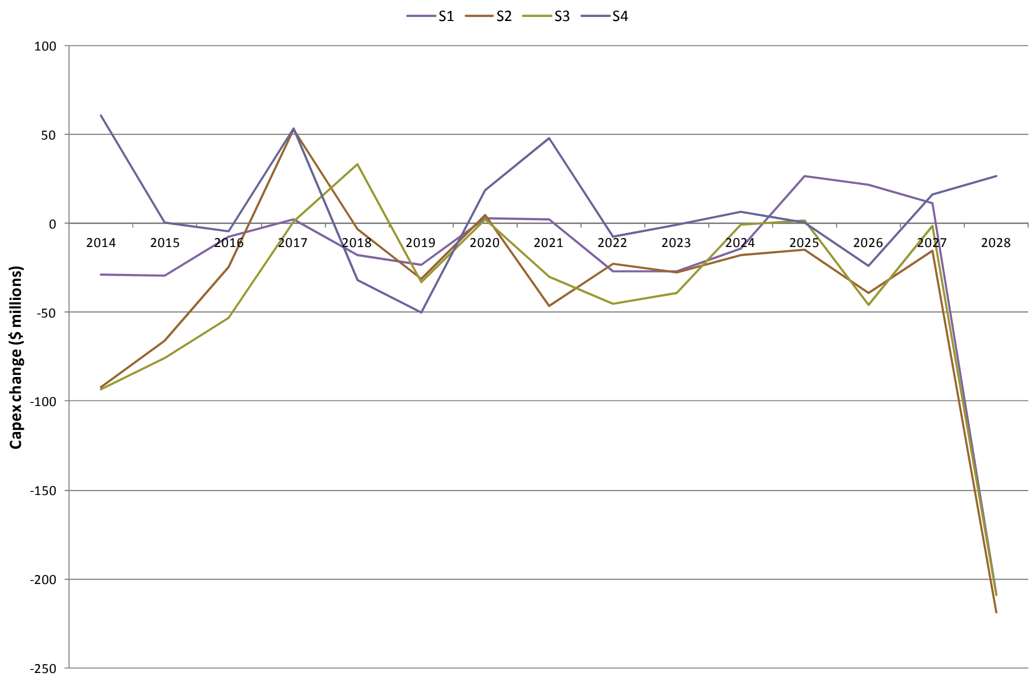


Figure 12 – Ausgrid profile of capex change (by regulatory period)

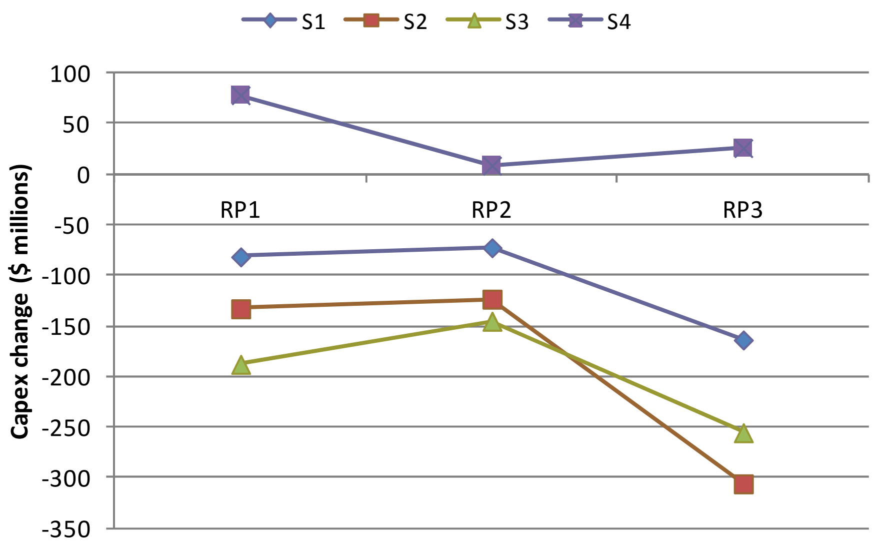


Figure 13 shows a similar profile of the change in reliability forecast by Ausgrid. This chart shows a much smoother and constant level of reliability change across the study period. The peaks in the reduction in reliability around 2018 to 2020 for Scenario 2 and Scenario 3 reflect changes to the timing of large sub-transmission projects in Ausgrid's urban network, associated with Schedule 1.

Figure 13 – Ausgrid profile of reliability change

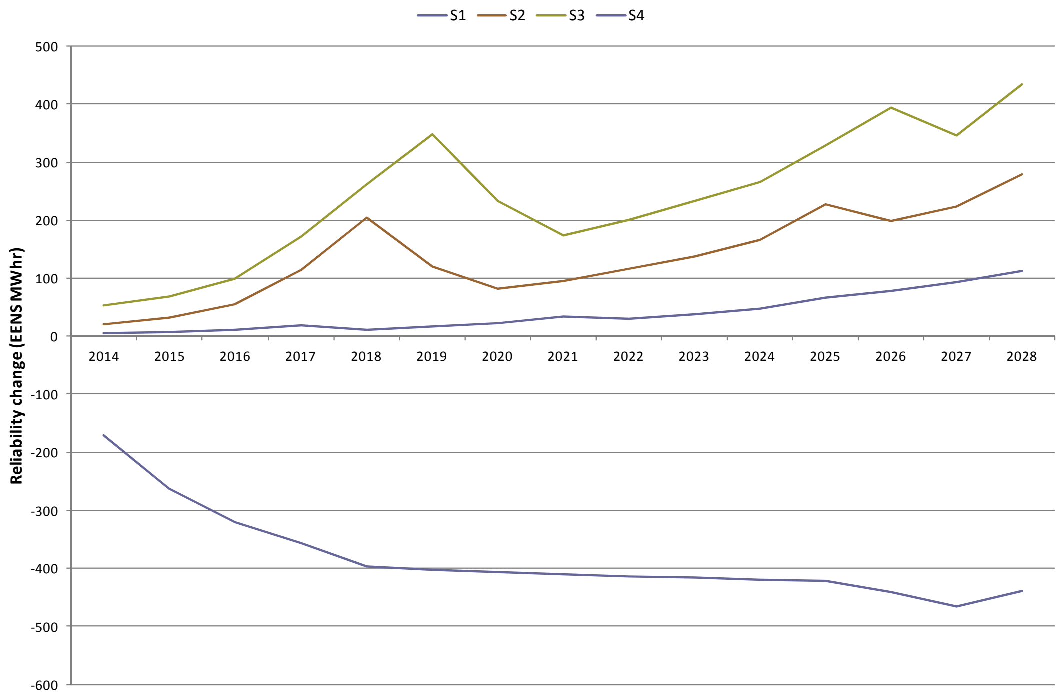


Figure 14 – Ausgrid profile of reliability change (by regulatory period)

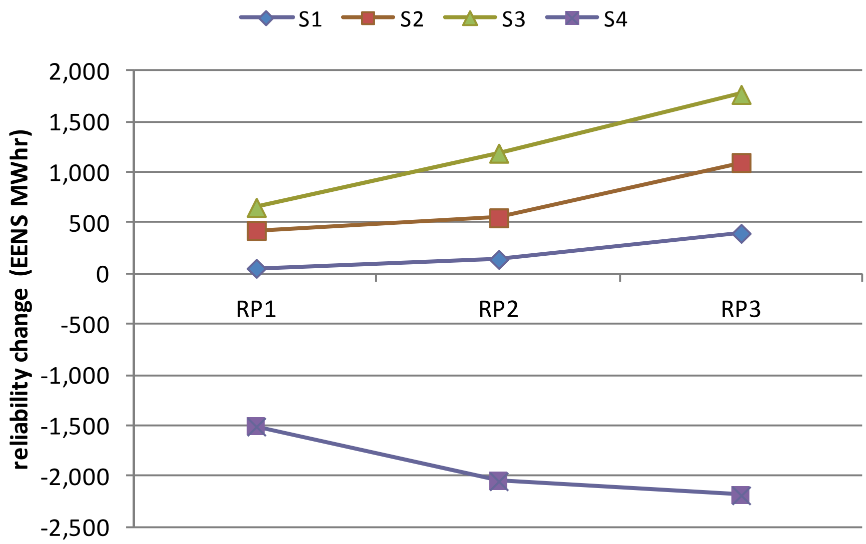


Table 8 and Table 9 provide a more detailed breakdown of the capex and reliability changes associated with each scenario. These tables indicate which components of the three schedules are contributing to the overall change, including the change as a percentage of the base case and its contribution to the overall change.

Reliability reduction scenarios

These results indicate that the changes to Schedule 1 are the most significant driver of changes to capex and reliability across all three reliability-reduction scenarios. Schedules 2 and 3 are effectively insignificant on the capex change across all three scenarios.

For Schedule 1, the introduction of load at risk for the CBD network appears to be the most significant contributor to the capex change with very little increase in expected energy not served. However, noting the point above on the large contribution in the final years of the study period, it would appear that these changes will have a far less significant impact on capex in the short to medium term.

Consequently, the changes to the load at risk criteria associated with the urban network should provide the greatest contribution to capex and reliability changes in the short to medium term.

For Schedule 2, the introduction of the confidence levels for assessing compliance has resulted in some small reductions that are relatively constant across the three scenarios. Interestingly, the capex on CBD feeders appear to be increasing for Scenario 3. This appears anomalous; however, it is mainly driven by an increase in compliance projects (over the base case) that are required at the end of the study period to counteract the reliability-reductions that are forecast to occur due to the deferment of the major projects associated with Schedule 1.

For Schedule 3, the reduced standards are affecting capex and reliability for Scenario 2 and Scenario 3. However, the introduction of the cap has not affected the forecasts.

Reliability improvement scenario

For Scenario 4, Schedule 1 is less significant on capex; however, we believe that this is due to an issue in the reporting. Ausgrid appears to be forecasting a capex reduction for the urban sub-transmission category. We have been advised that this amount does not reflect the total increase in capex due to the proposed changes, and this value would include an additional $142 million that Ausgrid considers would be incurred prior to 2014 (see discussion in Section 8.2.4.1). It is not clear whether a similar issue has caused the reported increase in expected energy not served for the urban sub-transmission category, which also appears anomalous.

Schedule 2 is the most significant on the change in capex and reliability, where the adoption of the 99% confidence level for complying to the existing standards associated with urban and short rural feeders appears to have a significant effect on capex and reliability.

For Schedule 3, the improvement in the existing standards contributes the least to the overall capex change.

Table 8 – Ausgrid capex summary – scenario and schedule changes

		Capex ($ million)					% of base case				% of total change			
		BC	S1	S2	S3	S4	S1	S2	S3	S4	S1	S2	S3	S4
Schedule 1 - design planning criteria														
Load type	*Network type*													
CBD	Sub-transmission	527.7	-210.6	-243.0	-245.1	43.2	-40%	-46%	-46%	8%	66%	43%	42%	38%
	Distribution	74.1	-1.9	-8.5	-10.8	8.9	-3%	-11%	-15%	12%	1%	2%	2%	8%
Urban	Sub-transmission	2,532.5	-55.3	-187.4	-192.3	-78.1	-2%	-7%	-8%	-3%	17%	33%	33%	-69%
	Distribution	1,294.4	-46.3	-112.1	-124.6	68.3	-4%	-9%	-10%	5%	15%	20%	21%	61%
Non-Urban	Sub-transmission	-	-	-	-	-	na	na	na	na	-	-	-	-
	Sub total	**4,428.7**	**-314.1**	**-550.9**	**-572.9**	**42.2**	**-7%**	**-12%**	**-13%**	**1%**	**99%**	**98%**	**97%**	**37%**
Schedule 2 - reliability standards														
	Feeder type													
	CBD	.9	-.3	-.2	1.4	-.3	-35%	-27%	160%	-38%	0%	0%	-0%	-0%
	Urban	-	-	-	-	34.8	na	na	na	na	-	-	-	31%
	Short Rural	3.2	-3.2	-3.2	-3.2	29.5	-100%	-100%	-100%	915%	1%	1%	1%	26%
	Long Rural	.2	-.2	-.2	-.2	1.1	-100%	-100%	-100%	444%	0%	0%	0%	1%
	Sub total	**4.3**	**-3.8**	**-3.7**	**-2.1**	**65.0**	**-87%**	**-85%**	**-48%**	**1500%**	**1%**	**1%**	**0%**	**58%**
Schedule 3 - individual feeder standards														
	Feeder type													
	CBD	-	-	-	-	-	na	na	na	na	-	-	-	-
	Urban	25.2	-	-6.5	-11.8	4.7	-	-26%	-47%	19%	-	1%	2%	4%
	Short Rural	3.6	-	-.9	-1.4	.8	-	-25%	-39%	22%	-	0%	0%	1%
	Long Rural	-	-	-	-	-	na	na	na	na	-	-	-	-
	Sub total	**28.8**	**-**	**-7.4**	**-13.2**	**5.5**	**-**	**-26%**	**-46%**	**19%**	**-**	**1%**	**2%**	**5%**
Total		**4,461.8**	**-317.8**	**-562.0**	**-588.1**	**112.7**	**-7%**	**-13%**	**-13%**	**3%**	**100%**	**100%**	**100%**	**100%**

Table 9 – Ausgrid reliability summary – scenario and schedule changes

		EEENS (MWhr)					% of base case				% of total change			
		BC	S1	S2	S3	S4	S1	S2	S3	S4	S1	S2	S3	S4
Schedule 1 - design planning criteria														
Load type	*Network type*													
CBD	Sub-transmission	-		6	16	-	na	na	na	na	0%	0%	0%	-
	Distribution	-	2	9	23	-	na	na	na	na	0%	0%	1%	-
Urban	Sub-transmission	335	271	923	1,396	75	81%	276%	417%	23%	46%	45%	39%	-1%
	Distribution	-1,109	211	519	1,011	-109	-19%	-47%	-91%	10%	36%	25%	28%	2%
Non-Urban	Sub-transmission	-14	-	12	12	-8	-	-81%	-81%	54%	-	1%	0%	0%
	Sub total	**-788**	**485**	**1,469**	**2,457**	**-41**	**-61%**	**-186%**	**-312%**	**5%**	**82%**	**71%**	**68%**	**1%**
Schedule 2 - reliability standards														
	Feeder type													
	CBD	-31	-	-7	-36	2	1%	23%	116%	-7%	-0%	-0%	-1%	-0%
	Urban	-	-	-	-	-2,416	na	na	na	na	-	-	-	42%
	Short Rural	-94	94	94	94	-2,621	-100%	-100%	-100%	2782%	16%	5%	3%	46%
	Long Rural	-12	12	12	12	-101	-100%	-100%	-100%	833%	2%	1%	0%	2%
	Sub total	**-138**	**106**	**99**	**70**	**-5,135**	**-77%**	**-72%**	**-51%**	**3732%**	**18%**	**5%**	**2%**	**89%**
Schedule 3 - individual feeder standards														
	Feeder type													
	CBD	-	-	-	-	-	na	na	na	na	-	-	-	-
	Urban	-2,603	-	405	920	-482	-	-16%	-35%	19%	-	20%	25%	8%
	Short Rural	-380	-	98	161	-85	-	-26%	-42%	22%	-	5%	4%	1%
	Long Rural	-	-	-	-	-	na	na	na	na	-	-	-	-
	Sub total	**-2,983**	**-**	**504**	**1,081**	**-567**	**-**	**-17%**	**-36%**	**19%**	**-**	**24%**	**30%**	**10%**
Total		**-3,909**	**591**	**2,071**	**3,608**	**-5,743**	**-15%**	**-53%**	**-92%**	**147%**	**100%**	**100%**	**100%**	**100%**

7.2 Endeavour capex and reliability profile

7.2.1 Base case

Figure 15 shows the base case capex through the study period associated with each of the three schedules. This clearly indicates that Schedule 1 is by far the most significant driver of capex throughout the period. Given this, Figure 16 shows a further breakdown of Schedule 1 by network type.

Figure 15 – Endeavour base case capex (contribution by schedule)

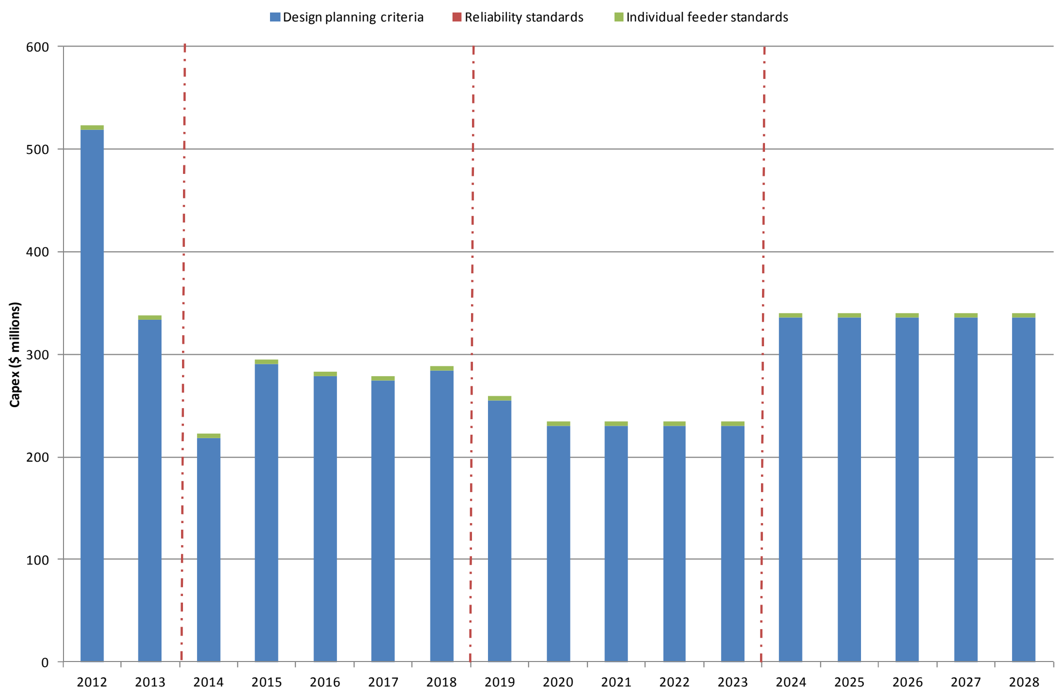
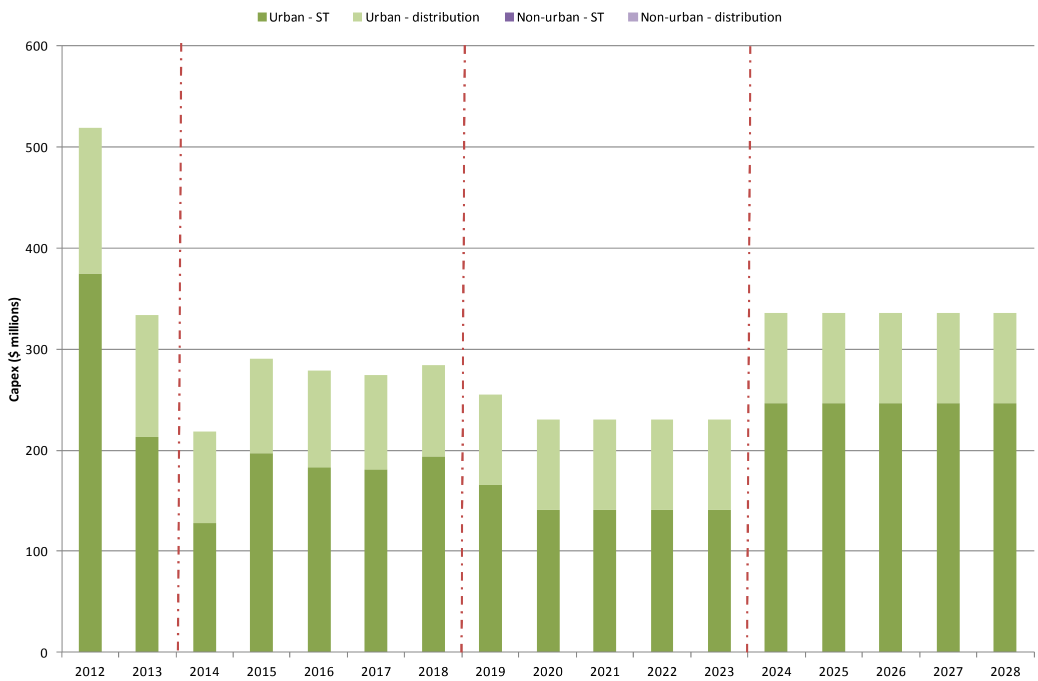


Figure 16 – Endeavour base case capex – Schedule 1



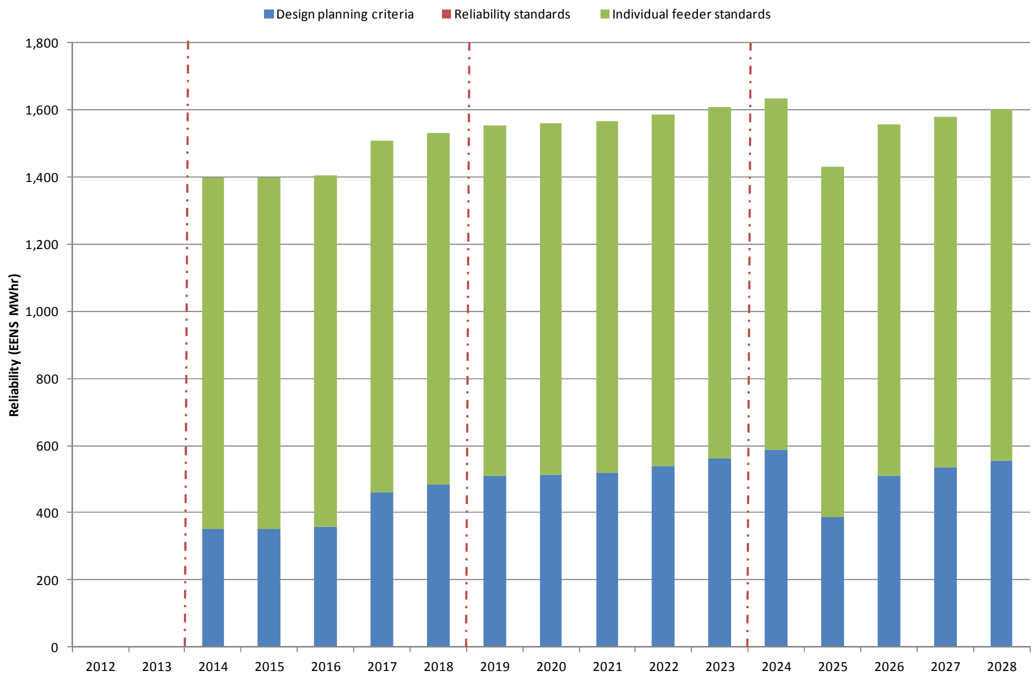
The two figures show capex will be relatively constant in RP1 and RP2, although at a much lower level than the current period. This capex level increases in RP3. The largest portion of capex is associated with the urban sub-transmission network.

Figure 17 shows the base case reliability through the study period associated with each of the three schedules. This chart suggests that Schedule 3 is the most significant contributor to expected energy not served throughout the period. However, this is a little misleading. For Schedule 3, the base case reflects the expected energy not served in the feeders that would be considered non-compliant – it is not the improvement in reliability that results from compliance works associated with Schedule 3 [10].

The level of expected energy not served is increasing slightly through the study period, due to an increase associated with Schedule 1.

[10] This is different to how Ausgrid has reported the Schedule 3 base case reliability, which does reflect the improvement through forecast compliance works.

Figure 17 – Endeavour base case reliability (contribution by schedule)



7.2.2 Scenarios

Figure 18 and Figure 19 show the profile of capex change forecast by Endeavour.

For the reliability-reduction scenarios, the capex change is relatively constant for Scenario 1. However, for the other two more extreme scenarios, Scenario 2 and Scenario 3, the capex change suggests a stepped increase, particularly in RP3. This increase largely reflects the deferral of large sub-transmission projects in Endeavour's urban network, associated with Schedule 1. As noted above, the base case suggests that a new wave of investment in this part of the network may begin to occur at this time, under the existing licence conditions.

The stepped pattern is due to the methodology Endeavour applied to populate the template. This methodology averages a yearly forecast over each 5-year period. In reality, such a pronounced step may not be expected.

Figure 18 – Endeavour profile of capex change

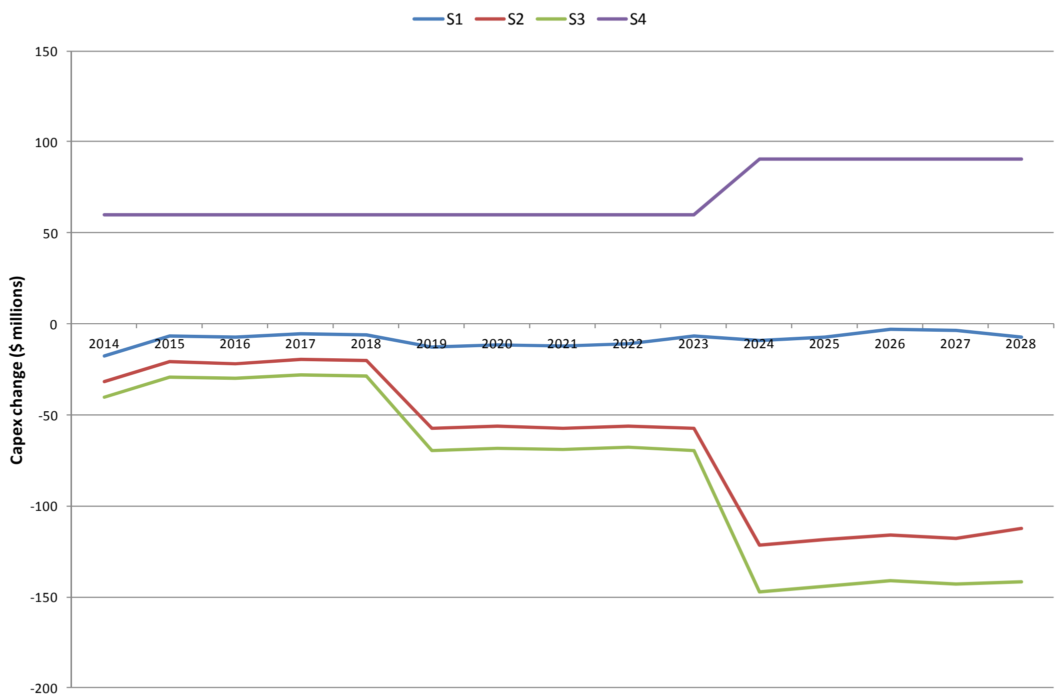


Figure 19 – Endeavour profile of capex change (by regulatory period)

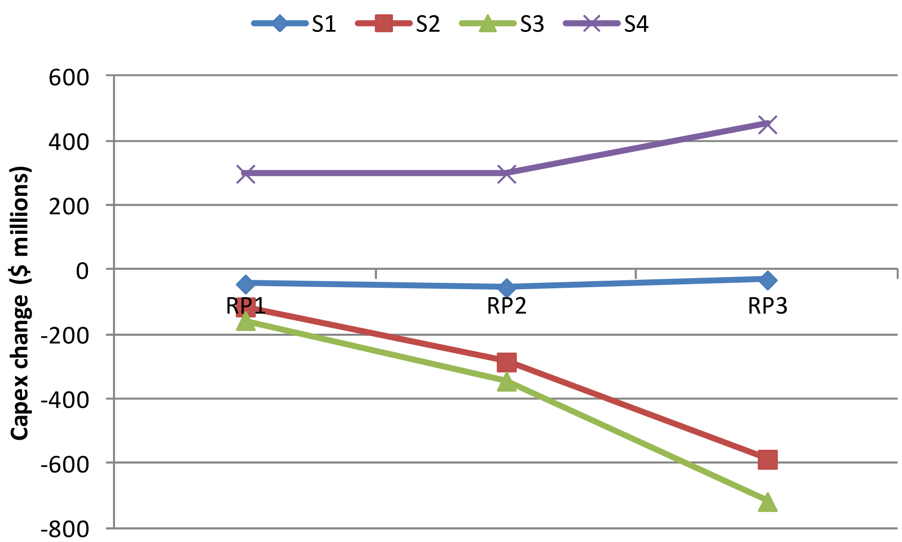


Figure 20 and Figure 21 show similar profiles of the change in reliability forecast by Endeavour. These graphs show reliability reducing very significantly in RP3 for Scenario 2 and Scenario 3. Similar to the capex reduction noted above, the reliability reduction reflects the deferral of the large sub-transmission projects in Endeavour's urban network, associated with Schedule 1.

For Scenario 4 (reliability-improvement), reliability appears to be getting worse. This worsening appears to be driven by increases in expected energy not served associated with changes to Schedule 1. However, as we will discuss in Section 8.2.4.2, we believe that this anomaly is a result of the methodology Endeavour has applied to calculate expected energy not served for this scenario. We believe that the expected energy not served would show an improvement across the study period. Figure 21 also shows our rough estimate of the reliability improvement we expect for this scenario[11].

Figure 20 – Endeavour profile of reliability change

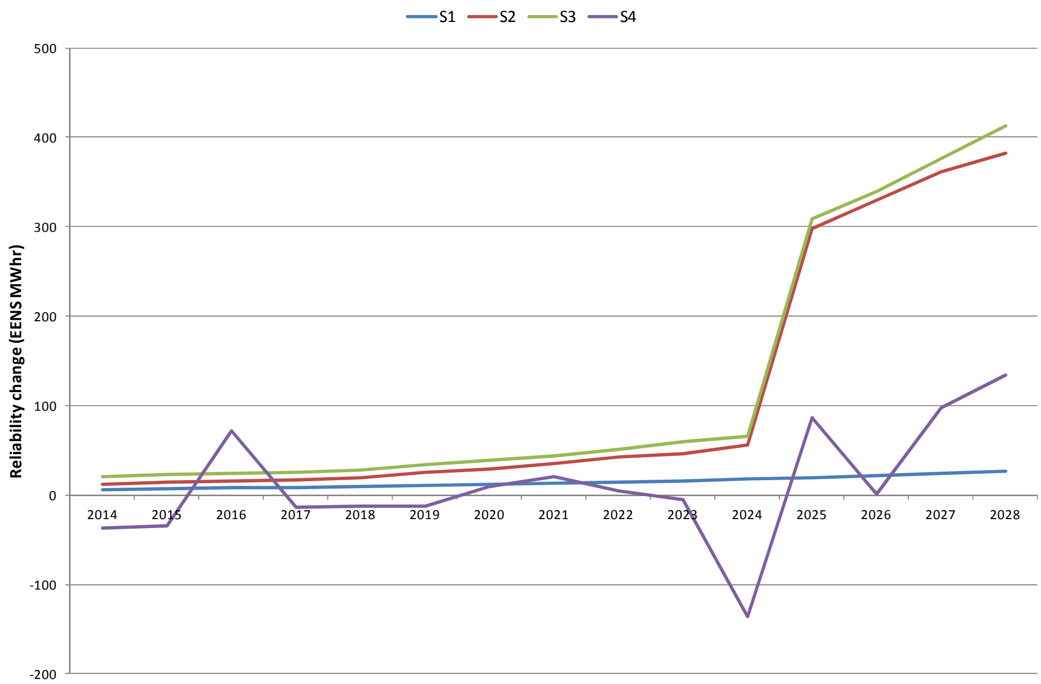
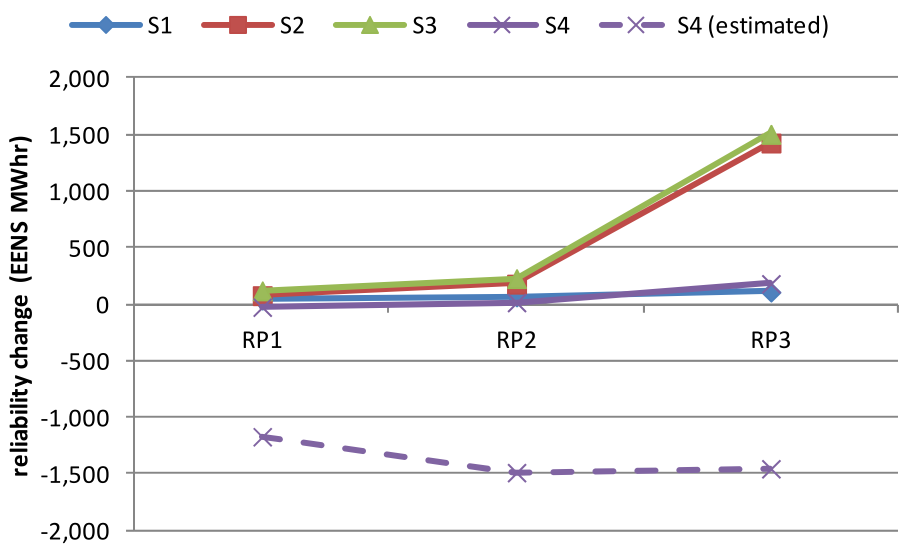


Figure 21 - Endeavour profile of reliability change (by regulatory period)



[11] We estimate that the reduction in expected energy not served could be around 25% to 50% of the base case, based upon typical load duration curves for Endeavour and the increase in maximum demand from the 50% to the 10% probability of exceedance. Figure 21 shows our estimated reliability change associated with the upper limit of this range (50%).

Table 10 and Table 11 provide a more detailed breakdown of the capex and reliability changes associated with each scenario. These tables indicate which components of the three schedules are contributing to the overall change, including the change as a percentage of the base case and its contribution to the overall change.

Reliability reduction scenarios

These results indicate that the changes to Schedule 1 are the most significant driver of changes to capex and reliability across all three reliability-reduction scenarios.

For Schedule 1, the urban network category produces all capex and reliability changes. For Scenario 1, the sub-transmission and distribution network provide similar modest changes in capex for little change in reliability. However, for Scenarios 2 and 3, the urban sub-transmission network contributes far more significantly to the capex and reliability changes.

For Schedule 2, Endeavour considers that it already outperforms the existing standards by some margin. As such, it is not forecasting any capex or associated reliability change for Schedule 2.

For Schedule 3, the reduced standards are affecting capex and reliability for Scenario 2 and Scenario 3. However, the introduction of the cap has not affected the forecasts.

Reliability improvement scenario

For Scenario 4, Schedule 1 is still the most significant on capex. However, there are some issues with the calculation and reporting of capex and reliability for this Scenario, as follows:

- Endeavour has not provided a forecast for urban distribution feeders (capex or reliability).
- As noted above, Endeavour has also calculated the reliability change associated with sub-transmission incorrectly. This is resulting in an apparent increase in the expected energy not served from the base case, when a reduction should occur.

For Schedule 2, Endeavour considers that its reliability is so much better than the existing standards that it will still comply to the 99% confidence level associated with this standard. As such, it is not anticipating a capex or reliability change due to this schedule.

Endeavour is forecasting a modest increase in capex and associated reduction in unserved energy, due to the improvements to the existing Schedule 3 standards. The changes to capex and reliability are constant throughout the study period. These changes are most significant for its urban feeder category.

Table 10 – Endeavour capex summary – scenario and schedule changes

		Capex ($ million)					% of base case				% of total change			
		BC	S1	S2	S3	S4	S1	S2	S3	S4	S1	S2	S3	S4
Schedule 1 - design planning criteria														
Load type	*Network type*													
CBD	Sub-transmission	-	-	-	-	-	na	na	na	na	-	-	-	-
	Distribution	-	-	-	-	-	na	na	na	na	-	-	-	-
Urban	Sub-transmission	2,842.6	-68.0	-884.5	-1,088.7	969.6	-2%	-31%	-38%	34%	53%	90%	89%	92%
	Distribution	1,356.4	-60.0	-91.5	-95.3	-	-4%	-7%	-7%	-	47%	9%	8%	-
Non-Urban	Sub-transmission	-	-	-	-	-	na	na	na	na	-	-	-	-
	Sub total	**4,199.0**	**-128.0**	**-976.0**	**-1,183.9**	**969.6**	**-3%**	**-23%**	**-28%**	**23%**	**100%**	**99%**	**97%**	**92%**
Schedule 2 - reliability standards														
	Feeder type													
	CBD	-	-	-	-	-	na	na	na	na	-	-	-	-
	Urban	-	-	-	-	-	na	na	na	na	-	-	-	-
	Short Rural	-	-	-	-	-	na	na	na	na	-	-	-	-
	Long Rural	-	-	-	-	-	na	na	na	na	-	-	-	-
	Sub total	**-**	**-**	**-**	**-**	**-**	**na**	**na**	**na**	**na**	**-**	**-**	**-**	**-**
Schedule 3 - individual feeder standards														
	Feeder type													
	CBD	-	-	-	-	-	na	na	na	na	-	-	-	-
	Urban	48.0	-	-4.5	-27.0	73.5	-	-9%	-56%	153%	-	0%	2%	7%
	Short Rural	16.5	-	-4.5	-6.0	6.0	-	-27%	-36%	36%	-	0%	0%	1%
	Long Rural	-	-	-	-	-	na	na	na	na	-	-	-	-
	Sub total	**64.5**	**-**	**-9.0**	**-33.0**	**79.5**	**-**	**-14%**	**-51%**	**123%**	**-**	**1%**	**3%**	**8%**
Total		**4,263.5**	**-128.0**	**-985.0**	**-1,216.9**	**1,049.1**	**-3%**	**-23%**	**-29%**	**25%**	**100%**	**100%**	**100%**	**100%**

Table 11 – Endeavour reliability summary – scenario and schedule changes

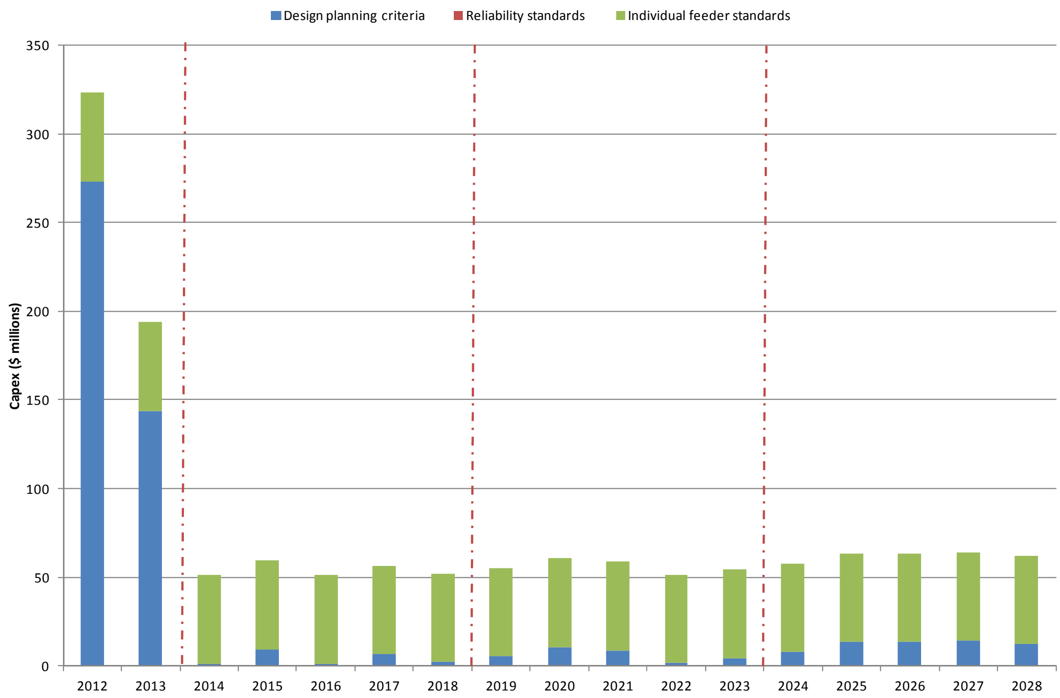
		EENS (MWhr)					% of base case				% of total change			
		BC	S1	S2	S3	S4	S1	S2	S3	S4	S1	S2	S3	S4
Schedule 1 - design planning criteria														
Load type	*Network type*													
CBD	Sub-transmission	-	-	-	-	-	na	na	na	na	-	-	-	-
	Distribution	-	-	-	-	-	na	na	na	na	-	-	-	-
Urban	Sub-transmission	7,226	1	1,348	1,380	672	0%	19%	19%	9%	0%	80%	75%	387%
	Distribution	-	213	249	260	-	na	na	na	na	100%	15%	14%	-
Non-Urban	Sub-transmission	-	-	-	-	-	na	na	na	na	-	-	-	-
	Sub total	**7,226**	**214**	**1,597**	**1,639**	**672**	**3%**	**22%**	**23%**	**9%**	**100%**	**95%**	**89%**	**387%**
Schedule 2 - reliability standards														
	Feeder type													
	CBD	-	-	-	-	-	na	na	na	na	-	-	-	-
	Urban	-	-	-	-	-	na	na	na	na	-	-	-	-
	Short Rural	-	-	-	-	-	na	na	na	na	-	-	-	-
	Long Rural	-	-	-	-	-	na	na	na	na	-	-	-	-
	Sub total	**-**	**-**	**-**	**-**	**-**	**na**	**na**	**na**	**na**	**-**	**-**	**-**	**-**
Schedule 3 - individual feeder standards														
	Feeder type													
	CBD	-	-	-	-	-	na	na	na	na	-	-	-	-
	Urban	11,604	-	54	179	-465	-	0%	2%	-4%	-	3%	10%	-268%
	Short Rural	4,082	-	33	33	-33	-	1%	1%	-1%	-	2%	2%	-19%
	Long Rural	-	-	-	-	-	na	na	na	na	-	-	-	-
	Sub total	**15,687**	**-**	**87**	**212**	**-498**	**-**	**1%**	**1%**	**-3%**	**-**	**5%**	**11%**	**-287%**
Total		**22,912**	**214**	**1,684**	**1,852**	**174**	**1%**	**7%**	**8%**	**1%**	**100%**	**100%**	**100%**	**100%**

7.3 Essential capex and reliability profile

7.3.1 Base case

Figure 22 shows the base case capex through the study period associated with each of the three schedules. This indicates that Schedule 3 is by far the most significant driver of capex throughout the period. It is noted however that capex associated with Schedule 1 is forecast to drop off considerably in the next regulatory period from the level incurred in the current.

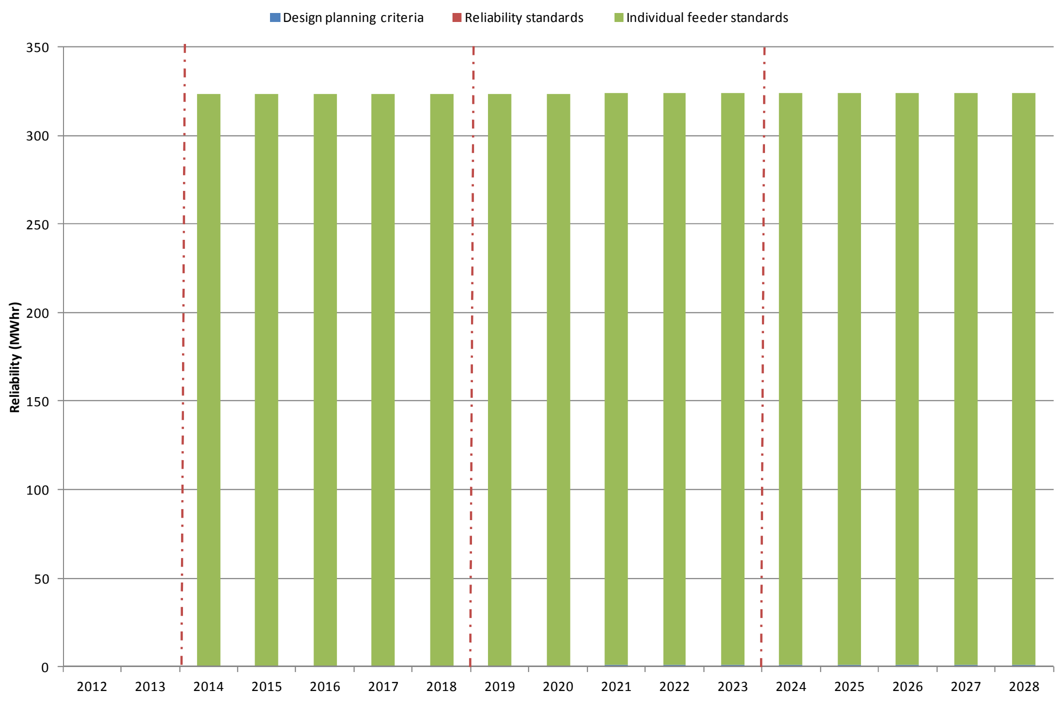
Figure 22 – Essential base case capex (contribution by schedule)



It is also worth noting that Essential is the only DNSP forecasting base case opex. This is only a small proportion of overall expenditure however. Essential has also included overheads in its base case capex, which other DNSPs have omitted.

Figure 23 shows the base case reliability through the study period associated with each of the three schedules. This level is constant through the study period. This chart suggests that Schedule 3 is the only contributor to expected energy not served throughout the period. However, this is a little misleading. Similar to Endeavour above, for Schedule 3, the base case reflects the expected energy not served in the feeders that would be considered non-compliant – it is not the improvement in reliability that results from the compliance work associated with Schedule 3.

Figure 23 – Essential base case reliability (contribution by schedule)



7.3.2 Scenarios

Figure 24 and Figure 25 show the profile of capex change forecast by Essential.

Unlike Ausgrid and Endeavour, the capex change is relatively constant through the study period, with only a small increase as we move through the study period.

The one exception concerns the reliability improvement scenario, Scenario 4, where there is a significant increase in the first year of the study period reducing to a constant level by the third year. This is due to the increased reliability standard associated with the Schedule 3 change. This results in a step increase in the number of non-compliant feeders at the commencement of the study period. In reality, we would expect that there would be some transitional arrangements associated with such an improvement, as such it may be expected that this increase would be allowed to occur at least over the first 5-year period.

Figure 24 – Essential profile of capex change

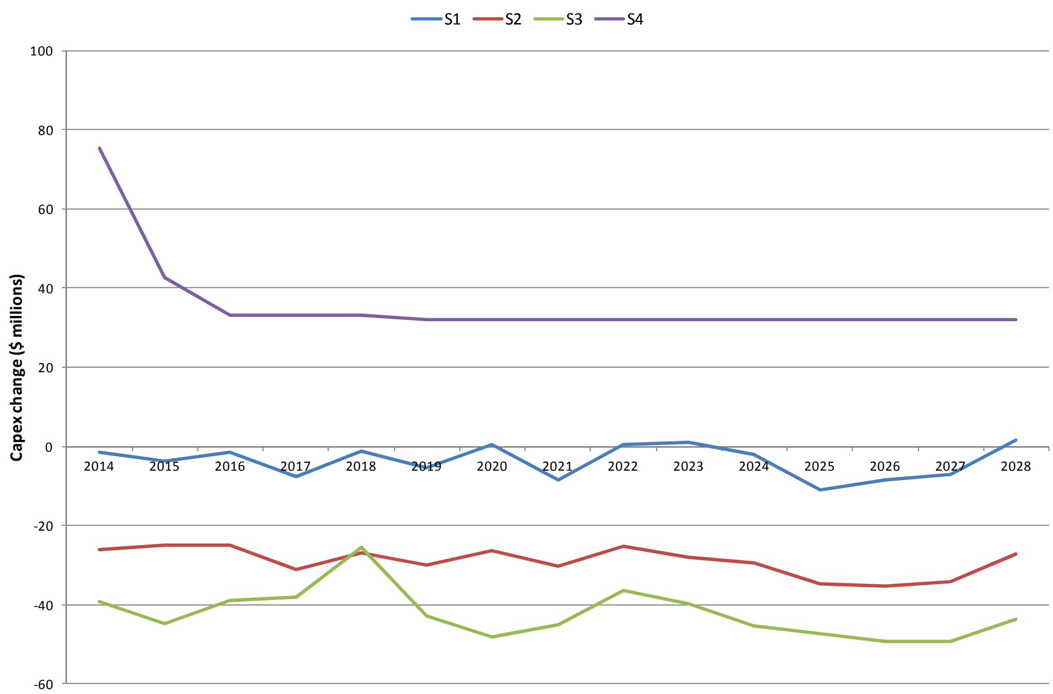


Figure 25 – Essential profile of capex change (by regulatory period)

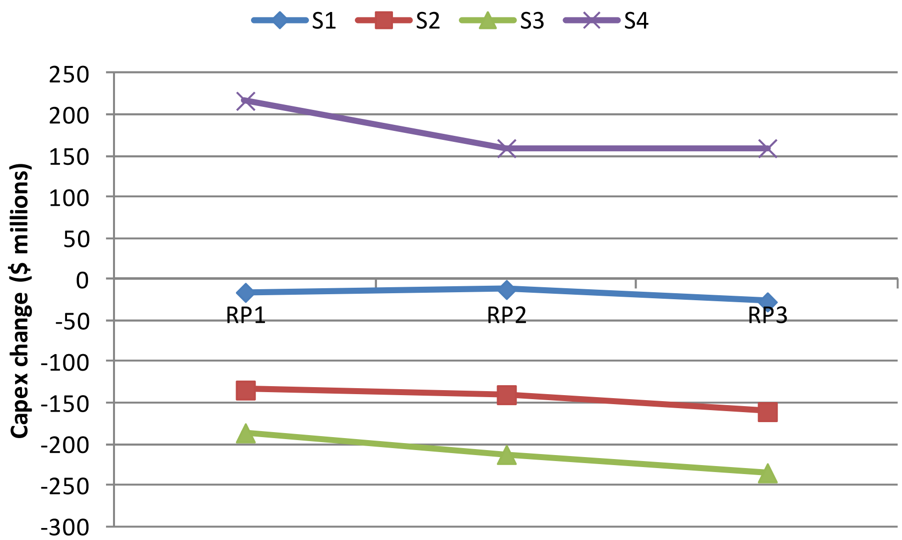


Figure 26 and Figure 27 show similar profiles of the change in reliability forecast by Essential. These graphs show reliability reducing very significantly for Scenario 2 and Scenario 3. As is discussed in the methodology section, this reduction is due to the changes proposed to Schedule 3. In this regard, under Essential's modelling, the cap on the number of non-compliant feeders to be addressed in each year is resulting in an escalating number of non-compliant feeders remaining on the network. This is resulting in the expected energy not served through these feeders also increasing each year. This effect does not occur under Scenario 1 becasue, for this scenario, the cap has very little impact on the number of feeders addressed each year.

Figure 26 – Essential profile of reliability change

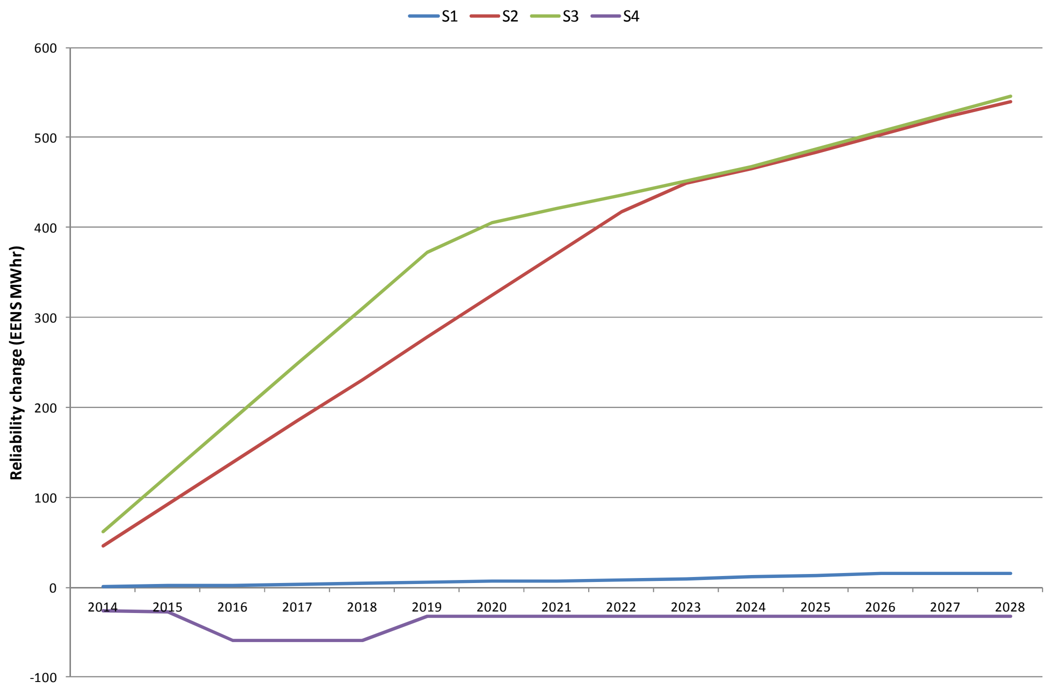


Figure 27 - Essential profile of reliability change (by regulatory period)

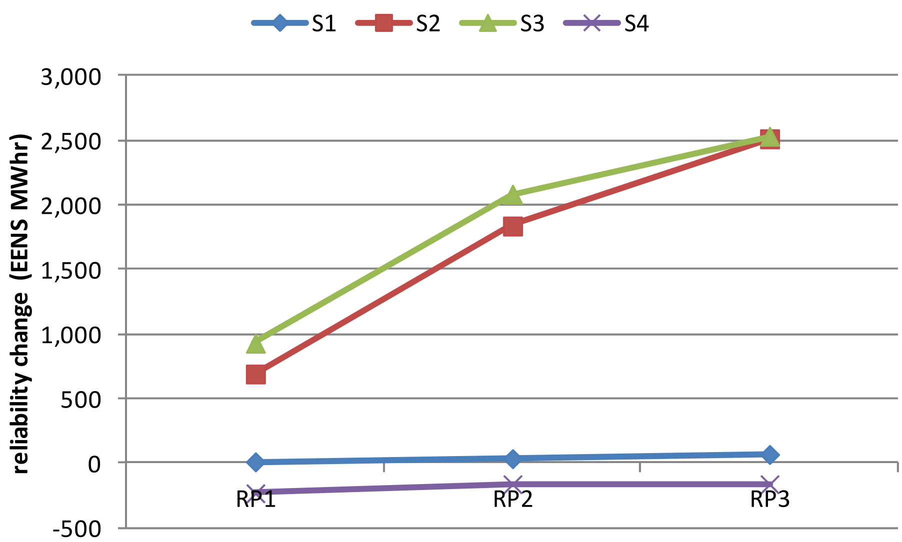


Table 12 – Essential capex summary – scenario and schedule changes

		Capex ($ million)					% of base case				% of total change			
		BC	S1	S2	S3	S4	S1	S2	S3	S4	S1	S2	S3	S4
Schedule 1 - design planning criteria														
Load type	*Network type*													
CBD	Sub-transmission	-	-	-	-	-	na	na	na	na	-	-	-	-
	Distribution	-	-	-	-	-	na	na	na	na	-	-	-	-
Urban	Sub-transmission	-	-	-	-	-	na	na	na	na	-	-	-	-
	Distribution	99.4	-39.9	-58.9	-64.1	-	-40%	-59%	-64%	-	73%	14%	10%	-
Non-Urban	Sub-transmission	13.5	-	-	-13.5	-	-	-	-100%	-	-	-	2%	-
	Sub total	**112.9**	**-39.9**	**-58.9**	**-77.6**	**-**	**-35%**	**-52%**	**-69%**	**-**	**73%**	**14%**	**12%**	**-**
Schedule 2 - reliability standards														
	Feeder type													
	CBD	-	-	-	-	-	na	na	na	na	-	-	-	-
	Urban	-	-	-	-	1.2	na	na	na	na	-	-	-	0%
	Short Rural	-	-	-	-	4.4	na	na	na	na	-	-	-	1%
	Long Rural	-	-	-	-	.2	na	na	na	na	-	-	-	0%
	Sub total	**-**	**-**	**-**	**-**	**5.8**	**na**	**na**	**na**	**na**	**-**	**-**	**-**	**1%**
Schedule 3 - individual feeder standards														
	Feeder type													
	CBD	-	-	-	-	-	na	na	na	na	-	-	-	-
	Urban	75.0	-2.3	-37.8	-53.5	51.8	-3%	-50%	-71%	69%	4%	9%	8%	10%
	Short Rural	465.0	-10.8	-234.0	-353.7	326.1	-2%	-50%	-76%	70%	20%	54%	56%	61%
	Long Rural	210.0	-2.0	-103.8	-148.4	152.2	-1%	-49%	-71%	72%	4%	24%	23%	28%
	Sub total	**750.0**	**-15.0**	**-375.6**	**-555.6**	**530.1**	**-2%**	**-50%**	**-74%**	**71%**	**27%**	**86%**	**88%**	**99%**
Total		**862.9**	**-54.9**	**-434.5**	**-633.2**	**535.8**	**-6%**	**-50%**	**-73%**	**62%**	**100%**	**100%**	**100%**	**100%**

Table 13 – Essential reliability summary – scenario and schedule changes

		EENS (MWhr)					% of base case				% of total change			
		BC	S1	S2	S3	S4	S1	S2	S3	S4	S1	S2	S3	S4
Schedule 1 - design planning criteria														
Load type	*Network type*													
CBD	Sub-transmission	-	-	-	-	-	na	na	na	na	-	-	-	-
	Distribution	-	-	-	-	-	na	na	na	na	-	-	-	-
Urban	Sub-transmission	-	-	-	-	-	na	na	na	na	-	-	-	-
	Distribution	-	33	59	78	-	na	na	na	na	14%	1%	1%	-
Non-Urban	Sub-transmission	11	-	-	11	-	-	-	100%	-	-	-	0%	-
	Sub total	**11**	**33**	**59**	**88**	**-**	**316%**	**566%**	**841%**	**-**	**14%**	**1%**	**2%**	**-**
Schedule 2 - reliability standards														
	Feeder type													
	CBD	-	-	-	-	-	na	na	na	na	-	-	-	-
	Urban	-	-	-	-	-20	na	na	na	na	-	-	-	4%
	Short Rural	-	-	-	-	-108	na	na	na	na	-	-	-	20%
	Long Rural	-	-	-	-	-5	na	na	na	na	-	-	-	1%
	Sub total	**-**	**-**	**-**	**-**	**-133**	**na**	**na**	**na**	**na**	**-**	**-**	**-**	**24%**
Schedule 3 - individual feeder standards														
	Feeder type													
	CBD	-	-	-	-	-	na	na	na	na	-	-	-	-
	Urban	452	20	465	509	-39	4%	103%	113%	-9%	8%	9%	9%	7%
	Short Rural	2,382	103	2,452	2,686	-205	4%	103%	113%	-9%	42%	49%	48%	37%
	Long Rural	2,011	87	2,070	2,267	-173	4%	103%	113%	-9%	36%	41%	41%	31%
	Sub total	**4,845**	**209**	**4,987**	**5,462**	**-417**	**4%**	**103%**	**113%**	**-9%**	**86%**	**99%**	**98%**	**76%**
Total		**4,855**	**243**	**5,047**	**5,551**	**-550**	**5%**	**104%**	**114%**	**-11%**	**100%**	**100%**	**100%**	**100%**

Table 12 and Table 13 provide a more detailed breakdown of the capex and reliability changes associated with each scenario. These tables indicate which components of the three schedules are contributing to the overall change, including the change as a percentage of the base case and its contribution to the overall change.

Reliability reduction scenarios

These results indicate that the changes to Schedule 1 are the most significant driver of changes to capex for Scenario 1. However, for Scenarios 2 and 3, the changes associated with Schedule 3 are far more significant. Schedule 3 is also the most significant, across all three scenarios, with respect to the reliability change.

As noted above, it is the introduction of the cap associated with Schedule 3 that results in this pattern of change across the scenarios.

For Schedule 1, the urban distribution category produces the main changes in capex across all three scenarios, indicating a modest increase from Scenario 1 to Scenario 3. For Scenario 3, Essential is also forecasting a reduction in capex on its non-urban network. Furthermore, although not included on the charts and tables in this report, Essential is also forecasting a small increase in opex ($2.8 million over the study period) associated with Scenario 3.

For Schedule 2, Essential considers that it already complies with the existing standards to the confidence levels associated with the three scenarios. As such, it is not forecasting any capex or associated reliability change for Schedule 2.

Reliability improvement scenario

For Scenario 4, Schedule 3 is the main contributor to the capex and reliability changes.

Schedule 2 has a very minor effect on capex, but a more significant effect on reliability. As noted in Section 8.4 however, we believe that Essential may be understating the reliability improvement. In this regard, Essential does not appear to be carrying the reliability improvements forward from the year that they occur. We estimate that this could result in an additional reduction in expected energy not served for Essential of around 270 MWhr.

For Scenario 4, Essential has not provided a forecast associated with Schedule 1. We would however expect that this scenario would result in some material increase in capex from the base case. Given the base case reliability is already very low, it may be expected that there would be very little change in reliability associated with the additional capex. However, given the level of capex and reliability associated with the base case, we would not expect the capex or reliability changes to be that large, compared to the reported Schedule 3 changes.

8 Review of forecasting methodologies

8.1 Introduction

In this section, we discuss our review of the methodologies that the DNSPs have applied to prepare their forecasts. An overview of the methodologies applied by each DNSP is provided in Appendix B.

In appreciating the scope of this review, it is important to note that due to the limited time for this assignment, the review can only be considered a high-level reasonableness review. Defining the forecast as reasonable reflects a modest degree of confidence that the forecasts are reasonably accurate for policy setting purposes. It is important to stress however that the review was not the more thorough and independent process that we undertake for the AER in order to assess reasonable revenue requirements.

The reasonableness tests we used for this review consider whether:

- the methodologies described by the DNSPs broadly reflect the types of modelling we may have expected the DNSPs to perform given the time available
- input parameters and associated assumptions are broadly in line with what we would expect.

This view has relied largely upon the explanation provided by the DNSPs and discussions with the DNSPs secondments to the AEMC. These explanations have been supported by the provision of some models and worked examples. However, we have not undertaken an exhaustive assessment of these models.

As noted in the section on our assignment methodology, this review has not included:

- significant independent analysis or network modelling
- benchmarking of the forecasts or underlying costs, against each other or DNSPs in other states
- a forensic audit of the underlying models to ensure that they do not contain errors and are an accurate reflection of the methodology documents.

That said, during this review we have found some errors in the forecast that have subsequently been corrected by the DNSPs. These issues are not discussed here. This section only focuses on the final forecasts and methodologies applied by the DNSPs.

On this matter, it is important to note that we have corrected some errors associated with Ausgrid's template. Ausgrid has given a tentative approval of these corrections, but has not provided a formal update of the template[12]. The template using our corrections is that reported and discussed in this report.

8.2 Schedule 1 – planning design criteria

8.2.1 Overview of the forecasting methodologies

As noted in Section 4, planning to comply with Schedule 1 is largely a proactive process. As such, preparing forecasts to maintain future compliance to these licence conditions is part of a DNSP’s business-as-usual practice. However, the horizon that the forecasts cover and the detail of the underlying plans will normally differ between the sub-transmission and distribution networks. This difference is due to the scale of the issues that need to be considered and the ability to undertake detailed assessment i.e. the sub-transmission network can be viewed as a low volume / high cost problem, whereas the distribution network is a high volume/ low cost problem.

Therefore, the typical forecasting horizons for the sub-transmission network may be 10 to 20 years. And this forecast may consist of specific projects to address specific compliance issues. The distribution network on the other hand, may have forecasts that only extend 3 to 5 years. And even these forecasts may be based upon high-level analysis that is intended to gauge the overall volume of work and cost, rather than specific locational issues.

For this review, a 15-year horizon is defined. As such, it was anticipated that this would extend past the period that many DNSPs may prepare plans, particularly at the distribution level. Therefore, even for the base-case, we expected that the DNSPs would need to develop simplified models and assumptions to prepare the forecasts.

Nonetheless, the methodologies employed by the DNSPs can be considered in terms of the following broad types:

- a bottom-up assessment, aimed at individual network components (e.g. substations and lines)
- a top-down approach, aimed at estimating work volumes or unserved energy without considering specific network needs.

Clearly, from the discussion above, the former is more suited to the sub-transmission network whereas the latter is more suited to the distribution network.

Furthermore, to a large extent, the capex forecasts have focused on the load at risk parameters within the licence conditions. For preparing the forecasts for each scenario, this parameter has generally been used to adjust capex timings from the base-case, rather than affecting the project scope considerably. Consequently, the various capex forecasting methodologies generally address the following requirements:

[12] See email, dated 30 April 2012, from Ausgrid

Forecasting the growth in the loading on network components	This involves defining the existing loading of a network component, and then escalating it using the relevant maximum demand forecast.
Assessing future non compliance	This involves determining appropriate network component ratings associated with the relevant security levels in the licence condition. The allowed maximum level of loading above that rating can then be determined from the load at risk parameter within the licence conditions and knowledge of the load duration curve for that network component (see discussion in Appendix A). The forecast load can then be compared against this loading limit to determine the time when non-compliance would occur.
Determine the project (or cost) to return the network to a compliant state	This involves determining the most appropriate development option to achieve compliance. For modelling purposes here, this may be based upon the most likely project for the particular circumstances or a typical project (and cost) that should be appropriate on average across the population.

With regard to the calculation of the expected unserved energy, this depends upon the above capex forecast. The methodologies to a broad extent are in accordance with the explanations given in Appendix A, and involve the following key components:

Assessing the level of load at risk	This involves comparing the loading in each year against the relevant ratings associated with the different security levels. The extent that the loading will be above these ratings in each year defines the load at risk.
Determining the energy at risk	This involves determining the amount of energy, associated with this load at risk. This can normally be approximated with reference to the relevant load duration curve. For the analysis here, the load duration curve over the study period has generally been assumed the same shape as the existing load duration curve.
Determining the probability that the network could be in the outage state, reflecting the relevant security standard	This concerns developing a probability of the event occurring that, depending on its timing, could result in energy not being supplied (e.g. involuntary load shedding) to ensure equipment ratings are not exceeded. For example, for N-1 conditions, this probability is normally derived from the relevant outage frequency (i.e. faults per year) multiplied by the average outage duration.

Calculating the expected energy not served	The calculation of the expected energy not served in each year simply involves multiplying the energy at risk in each year by the probability of the outage.

All three DNSPs have modelled sub-transmission separately from distribution. As such, our review of these methodologies can best be described in terms of these two components.

8.2.2 Sub-transmission methodologies

With regard to the sub-transmission capex methodologies, all DNSPs have based these upon a bottom-up analysis of individual network components (i.e. lines and substation). Nonetheless, there are subtle differences between each DNSP.

Essential and Ausgrid both appear to have long-term sub-transmission plans that extend across our study period. Therefore, their base case forecasts are developed from these actual plans. In the case of Essential, it is only anticipating the need for a few projects over the study period to meet the forecast demand. As we understand it, these projects are rural substation developments, which are not affected by our proposed changes. Consequently, Essential has not undertaken any formal modelling for the scenarios.

In the case of Ausgrid, for each scenario, it has assessed how the timing of each of its planned projects will be impacted by the proposed changes. This has involved analysis of the timing of non-compliance for each component, involving both quantitative analysis and engineering judgement to determine the final timing of individual projects.

Endeavour on the other hand, only has existing plans that extend across a 10-year period. Therefore, it has used a “hybrid” approach to prepare its capex forecasts. For the base case, it has used these plans for the early years of the study period. However, it has also assessed the timing of non-compliance for each network component throughout the study period. For the remaining years of the base case and for each scenario, this finding has been used to determine the capex forecast, assuming a typical historical cost per non-compliant component (lines and substations). This typical cost therefore may not be accurate for any individual network component, but across the population, it is considered to represent a reasonable estimate.

It is also worth noting that as Ausgrid’s existing plans allowed for some distribution works to relieve sub-transmission constraints. This has been carried through into this analysis, whereby there is a component allocated to the distribution network that relates to sub-transmission compliance issues. Ausgrid is the only DNSP to have allowed for this.

With regard to forecasting reliability, the Ausgrid and Endeavour methodologies are also based upon a bottom-up analysis of individual network components (i.e. lines and substations). Both methodologies include the key attributes listed above; however, as with the capex forecasts, there are some subtle differences.

Most notably, Endeavour has assessed the energy at risk for each network component. The probability of the outage has been derived from typical industry statistics.

Ausgrid on the other hand, to limit the extent of the analysis, has only assessed those network components that it considers will have a significant impact on expected energy not served. Its probability has been derived from a reliability model of its network.

Essential does not consider that there will be any material changes in the levels of load at risk on its sub-transmission network due to the Schedule 1. Therefore, it has not provided any forecasts. This is broadly in line with its position on capex.

8.2.3 Distribution methodologies

With regard to the distribution capex methodologies, Endeavour and Essential have used a bottom-up analysis of individual network feeders. In contrast, Ausgrid has used a top-down modelling approach.

Although the Endeavour and Essential approaches are similar, they do differ in subtle ways. Both approaches assess the loading and ratings of the trunk sections of their population of feeders to determine the timing of non-compliance. This approach uses a similar rationale to define the load limit for each feeder, as defined above. Both models then use an assumed project cost to determine the capex forecast.

To estimate the capex from these results, Endeavour assumes a single cost associated with each non-compliant feeder. This cost estimate is derived from the recent historical cost of projects to address non-compliant feeders. Essential on the other hand has assumed a range of typical project scopes and costs, which are assumed to apply at various utilisation levels, up to the non-compliance event. These range from minor augmentations up to a new feeder development.

Neither Endeavour nor Essential modelled the reliability improvement scenario (Scenario 4). In both cases, they considered that this was not possible as a 10% PoE forecast was not available.

Ausgrid has approached the problem differently, making use of a model that it uses internally to prepare medium and long-term forecasts for its distribution network. This model uses actual network data, but constructs a typical feeder arrangement for analysis. Overall feeder needs are then determined with reference to this typical feeder. We understand that Ausgrid considers that this approach is important for its circumstances, as many of its feeders would not be constrained by trunk section issues. Therefore, attempting to analyse the total population of actual feeders over this 15-year study period would be impractical.

The model forecasts new feeder numbers and lengths of new feeders. To estimate the capex, Ausgrid uses various feeder cost functions that map the cost per unit length to the load density of the feeder. These cost functions have been derived from historical project costs.

To forecast reliability, Endeavour and Ausgrid have used a top-down model, whereas Essential has used a bottom-up model.

The Endeavour and Ausgrid approaches both rely upon the assessment of expected unserved energy for a single feeder that represents the average feeder. The results of this single feeder model are then aggregated up, based upon the number of feeders forecast through the capex analysis. The models only focus on N-1 conditions.

The Essential model makes use of the individual feeder loading and rating data that underpins its capex forecast to calculate the expected unserved energy for each feeder. This reliability forecast inherently allows for the capex forecast. The Essential model assesses both normal and N-1 conditions.

Within all the approaches, energy at risk is transformed to expected energy using assumptions of outage frequency and duration. These appear to have been derived from historical reliability data.

8.2.4 Discussion

8.2.4.1 Capex methodologies

Although all DNSPs have approached the forecasting of capex differently, all approaches appear reasonable given the circumstances. In arriving at this view, the following points are important:

- We have considered the approaches used to determine the impact on the timing of non-compliance due to the load at risk parameters, and these align with our expectations on this matter. Furthermore, although this review has not been able to assess the accuracy of timing changes in detail, based upon available load duration curves, the levels of load at risk and typical deferral/advancement times determined by the DNSPs appear to correlate at a high-level.
- As noted in the introduction, it has not been possible in this review to undertake any form of detailed benchmarking of the capital cost assumptions. Nonetheless, the methodologies applied, which all appear to be based upon historical cost or cost estimates derived through the business-as-usual processes, seem reasonable given the circumstances. Furthermore, the cost assumptions used by the DNSPs do not appear to be clearly unreasonable, based upon our experience of industry costs.

Although we have accepted the approaches, in principle, as noted in the previous sections, there are a number of limitations in the forecasts associated with Scenario 4. As such, care will be needed in undertaking cost-benefit analysis associated with this scenario. The limitations are as follows:

- Ausgrid is forecasting a reduction in urban sub-transmission projects across the study period – not an increase as may be expected. We understand that this is because the methodology that Ausgrid applied advanced the timing of some projects (or parts of) to before the 2014 commencement date of our study period. Therefore, the capex change associated with these projects was not reported. Ausgrid has advised that this unreported capex amounts to a further increase of $142 million from the base case. Given any changes to the licence conditions would only be introduced for 2014 – and it is assumed that for Scenario 4 some transitional arrangement would provide a period to achieve full compliance – we believe it probably would have been more correct to limit any capex advancement to no earlier than 2014.

- Endeavour and Essential did not prepare a distribution-level forecast for this scenario. In our view, this scenario should increase capex from the base-case, as it will result in projects being advanced maybe by 3 to 5 years. However, it may have very little impact on reliability associated with energy at risk (as the existing licence conditions do not permit this for normal or N-1 conditions). It may be argued that there would be some reliability benefit however through the advancement of additional feeder projects.

8.2.4.2 Reliability methodologies

The methodologies the DNSPs have applied to determine the expected energy not served associated with sub-transmission components are in accordance with the principles discussed in this report. As they are based upon a bottom-up approach, of which we only have limited data, we have not assessed the accuracy of the approach in any detail. Nonetheless, based upon the descriptions and the work examples provided by the DNSPs we have not found any significant concerns with the methodologies used to determine the base case and three reliability-reduction scenarios.

In reaching this conclusion, it is noted that Ausgrid has not undertaken an assessment across all components. As such, it could be that this forecast understates the expected unserved energy. Given statements made by Ausgrid that this unmodelled amount should not be material, we see no pressing reason to disagree.

We do have concerns with the methodology Endeavour has used to determine the expected energy not served by its sub-transmission components for Scenario 4, the reliability improvement scenario. As noted in the preceding sections, Endeavour is forecasting an increase in expected energy not served in its sub-transmission network for this scenario – not a reduction as may be expected. As we understand it, this is due it calculating energy at risk and expected energy not served, based directly upon the 10% PoE maximum demand, without adjusting for the lower probability of this demand occurring. We believe that if this was allowed for then the true expected energy not served would be lower than the base case. Based upon load duration curves provided by Endeavour and the increase in demand from the 50% PoE level to the 10% PoE level, we estimate that the reduction in expected energy not served from the base case level may be in order of 25% to 50%.

We also have concerns with the methodologies used to determine expected energy not served at the distribution level, across all three DNSPs and all scenarios modelled. In all cases, we consider that the methodologies may overstate the expected energy not served.

In the case of Essential, we have two issues. The first concerns Essential's assumptions that unserved energy could occur under normal conditions for the base-case and Scenario 1. The licence conditions for these scenarios do not permit feeder loading above the normal rating, and as such, there should not be unserved energy under normal conditions (at least for the 50% PoE maximum demand). As far as we are aware, Essential agrees with this view.

The second issue is potentially far more significant. This issue concerns Essential's calculations of the expected energy not served for N-1 conditions. We have not been able to reconcile the calculations applied in its spreadsheets to those that we would expect. In this regard, what we define as energy at risk and unserved energy – and discuss in this report – is not what appears to be used in the Essential modelling. We consider that Essential may be significantly overstating expected energy at risk associated with its distribution feeders. Our calculations suggest that this may be relatively low during the study period. This view is supported by the existing loading of the feeder population, which is on average well below the N-1 rating of the feeders.

With regard to Ausgrid and Endeavour, we are concerned that the methodology, based upon an average feeder, may also overstate energy at risk across the population.

Based upon the number of feeders that the DNSPs are forecasting will be non-compliant for the various scenarios, and the worst case energy at risk that could be associated with these feeders, we estimate that the DNSPs may be overstating expected unserved energy considerably.

8.3 Schedule 3 – individual feeder standards

8.3.1 Overview of the forecasting methodologies

As noted in section 4.1, complying with Schedule 3 is largely a reactive process. As such, DNSPs do not need to prepare medium to long-term forecasts as part of their business-as-usual practices. Therefore, the DNSPs have had to develop a methodology to prepare a forecast of this largely reactive process.

An important factor here is the forecast of non-compliant feeders. The number of new feeders in any future year will consist of two components:

- **Feeders in the existing population of non-compliant feeders**. When a standard is introduced – as occurred in 2007 - then we may expect a population of the existing feeders to be non-compliant to the standard. Due to variability of events that affect reliability, we may only observe a proportion of these non-compliant feeders in any reporting period. However, as time advances, we would expect that feeders within the population would be found and addressed. Therefore, the population would reduce year-by-year, and consequently, the number of non-compliant feeders forecast each year should reduce year-by-year. This number may then trend towards a constant amount, which reflects the proportion of the non-compliant feeders that are not economical to address.
- **New non-compliant feeders entering the population.** As network assets degrade or the number of customers on a feeder increases then the feeder reliability may worsen. As such, feeders that were previously compliant may enter the population of non-compliant feeders. However, maintenance, asset replacement programs

and augmentation programs aimed at maintaining the performance of the network should limit the number of the existing feeders degrading to the extent that they will become non-compliant in the future. Nonetheless, there may still be a small proportion of feeders that may enter the population of non-compliant feeders each year.

Based upon the above, we may expect that the number of non-compliant feeders in each year would trend down to a constant level. The constant level would reflect the new feeders that may appear due to the degradation in performance or feeders that are not economical to address.

All DNSPs have developed models based upon very similar principles. These models predict future outcomes using historical data on feeder reliability, the number of non-compliant feeders, the volumes of projects undertaken, and the costs of those projects.

The various forecasting methodologies generally address the following key matters:

Forecasting the number of non-compliant feeders in each year	This number will reflect the reliability standard within the scenario. For example, if the standard is relaxed then fewer feeders should be non-compliant. Depending on the circumstances, the DNSPs have assumed whether they have reached the constant level or their existing population of non-compliant feeders is still being addressed.
Defining how many projects will be undertaken	The DNSPs have used a fixed proportion, based upon the historical ratio of non-compliant feeders to work volumes, to define the number of projects undertaken to address the forecast number of non-compliant feeders. The scenarios allow for a cap on the number of projects to be undertaken in any year. This cap is applied at this stage.
Determining the project cost	All DNSPs have based this cost estimate upon historical costs.
Determining the reliability improvement from these projects	All DNSPs have based this prediction upon the reliability improvements seen in the historical reliability data.

8.3.2 Discussion

We consider that the methodologies applied by each DNSP are reasonable, given the circumstances. In this regard, basing the forecasts largely upon the projection of recent history appears to be appropriate, given the time available.

As noted above, the most critical component of the methodology is the forecast of non-compliant feeders. In our view, given the standards were introduced in 2007, we may still be in a period when the existing population of non-compliant feeders is being addressed (i.e. the forecast is trending down). However, given the assumed action of maintenance and replacement programs, we would expect the number of new feeders found each year to be very low.

Broadly, the DNSP models are in line with this view. The one apparent exception is Essential. Essential is anticipating a much higher proportion of feeders will continue to be found to be non-compliant into the future (approximately 5% of its feeders) than other DNSPs (< 1% of feeders) – or what we were expecting. For the scenario modelling, this assumption has had a significantly detrimental effect on reliability through the action of the cap on feeder projects that we have proposed for this schedule. As this proportion is above the cap then an escalating number of non-compliant feeders remains on the network, and so, an escalating level of unserved energy occurs.

We have discussed this issue with Essential. Essential considers that its analysis of the historical trend in the numbers of non-compliant feeders suggests that it is now around the constant level. Moreover, it considers that this high proportion relative to other DNSPs is a consequence of the highly rural nature of its network. Essential's greater feeder length and exposure of feeders, compared to the other DNSPs, results in it having a much greater number of feeder segments (i.e. portions of a feeder between switching points) than the other two DNSPs. In Essential's view, the number of new feeders as a proportion of the number of segments is a more useful measure for comparative purposes. For Essential, this measure is approximately 1%, which is more in line with the other DNSPs.

We accept, in principle, Essential's reasoning. In this regard, while typical maintenance and replacement practices may on average maintain performance, as the length of a feeder increases then it is more likely that these practices may not be sufficient to ensure the feeder's reliability does not degrade beyond the feeder standard. As Essential has much longer feeders then there should be a greater proportion of its feeders that this may occur to. Therefore, the number of segments (rather than feeders) may be a more useful measure for comparative purposes as this reflects the relative differences in the lengths of the feeders between DNSPs.

We have tentatively accepted the Essential model, as we do not have specific evidence to support an alternative view. However, we believe there is still a possibility that the Essential model may be overstating the number of non-compliant feeders it will find over the study period, and this may continue to trend down to a lower number. In our view, Essential's trending of the historical number of non-compliant feeders – which suggests that Essential is now at a constant level - is not definitive on this issue. It may be that further trending down will occur, resulting in a lower number of new feeders being found to be non-compliant in the future. The result of this alternative outcome may be most significant on the capex and reliability forecasts in the second and third 5-year periods of the forecast. Therefore, the AEMC should consider the implications of this when assessing the various scenarios.

8.4 Schedule 2 – reliability standards

8.4.1 Overview of the forecasting methodologies

Assessing compliance to Schedule 2 requires a forecast of reliability over the study period. Similar to the above discussion on Schedule 3, a DNSP's maintenance and replacement programs are aimed at maintaining performance, and therefore, the existing reliability is a reasonable basis to project future reliability.

However, reliability can be affected to some degree by Schedule 1 (e.g. due to the load at risk) and Schedule 3 (due to the correction of poor performing feeders). Therefore, forecasting reliability may involve adjustments to account for these effects.

Endeavour considers that it is already achieving the standards by some margin, and as such, it is not anticipating that capex or reliability over the study period will be affected by the standards or our proposed changes. Therefore, it has not undertaken any formal modelling associated with this component of the licence conditions.

Essential and Ausgrid on the other hand have both used similar methodologies to prepare their forecasts. These methodologies address the following key matters:

Statistical analysis to determine the reliability target	Both DNSPs have applied statistical analysis of historical reliability data to determine the reliability targets associated with different confidence levels.
Forecasting reliability over the study period	This step involves adjusting current reliability to account for the future effects – most notably addressing Schedule 1 and Schedule 3. Ausgrid has allowed for the effects of Schedules 1 and 2, and the effect of increasing customer numbers. Essential has assumed that these effects are largely immaterial in its case.
Determining non-compliance	This simply involves assessing whether the above forecast of reliability will be worse than the target reliability, and if so, what this "gap" in reliability will be.
Determining the project cost associated with addressing the "gap"	Essential has assumed a solution (installation of reclosers) and then used a model of its network to determine the volume required. An assumed unit cost is then applied to produce the capex forecast. Ausgrid has used the historical cost per customer minute of improvement to estimate the capex.
Determining the reliability improvement from these projects	Both DNSPs assume that the reliability improvement is the "gap" calculated above.

8.4.2 Discussion

In principle, we consider that the methodologies applied by each DNSP are reasonable, given the circumstances. Based upon our understanding of Endeavour's current reliability, which recently has been significantly better than the existing standard, it seems reasonable to assume that the proposed changes would have a minimal effect on compliance requirements to this schedule over the study period.

For Ausgrid and Essential, although the methodologies and assumptions differ slightly, we do not find either to be unreasonable. In this regard, a significant difference is on the assumed effects of Schedule 1 and Schedule 3 actions, whereby Essential considers them negligible but Ausgrid has accounted for them. In the case of Ausgrid, the allowance for these effects is material.

This difference is most noticeable with regard to Schedule 3 works. We believe this difference is a consequence of the different underlying assumptions in the Schedule 3 models. For Essential, the feeders being addressed are assumed to be feeders that have degraded during the study period, resulting in them arising in the population of non-compliant feeders. Essential is then only assuming sufficient work is undertaken to address this degraded portion of reliability. As such, it does not affect the base line level of reliability. Ausgrid on the other hand appears to be assuming that it is largely addressing the existing population of non-compliant feeders, and as such, the works will improve their existing reliability.

In reality, we believe that the true outcome may be somewhere in between for both DNSPs. On balance however, given the particular circumstances of the two DNSPs, we consider that the different assumptions are reasonable for this exercise.

It is clear for this analysis however that there is the potential for an overlap between Schedule 2 and Schedule 3 standards, and to a lesser degree Schedule 2 and Schedule 1. As such, ensuring compliance to Schedule 2 may have unintended (possibly uneconomic) consequences over different periods. These issues will be discussed further in the next section, where we discuss the implications of the proposed changes.

We are also concerned that Ausgrid's assumed cost may not be appropriate for the reliability improvement scenario. This cost is based upon the recent historical costs to achieve reductions in customer minutes not supplied. While we accept that this may be appropriate for marginal reliability improvements. For the reliability improvement scenarios, Ausgrid is forecasting the need for fairly significant reliability improvements. For example, a 15% and 12% SAIDI improvement for the short rural and urban feeder categories respectively. In our view, it would be expected that achieving such significant improvements would be more costly than the historical average.

Finally, although we have accepted Essential's forecasting methodology, we believe that it may have reported the reliability improvement associated with Scenario 4 incorrectly. In this regard, it does not appear to have carried the reliability improvement (in terms of reduced expected energy not served) into the year following the improvement works. We estimate that this may result in a further reduction in expected energy not served of approximately 270 MWhr over the study period.

9 General discussion and conclusions

In this section, we summarise the overall findings of this review and provide some commentary that we consider may be relevant to the AEMC deliberations.

The section is structured in terms of the three schedules in the licence conditions.

Before turning to this discussion, it is important to note that we would expect that the confidence in the accuracy of the forecasts would reduce through the 15-year study period. The adoption of the 15-year study period was mainly chosen to aid in the appreciation of cyclical issues that may be particularly relevant to Schedule 1. Although forecasting to Schedule 1 over this time period is more usual, particularly for sub-transmission assets, the load forecast will be increasingly uncertain. Moreover, we do not consider it normal practice to prepare such long-term forecasts for Schedule 2 and 3, and as such, we have greater concerns over the effectiveness of many of the assumptions (which are based upon recent history) as we progress through the study period. Therefore, it will be important that this increasing uncertainty is kept in mind when evaluating the scenarios, particularly if the effects of the second half of the 15-year period become significant on decisions.

9.1 Schedule 1 – planning design standards

For Schedule 1, a similar set of changes to the licence conditions has been defined for the three reliability reduction scenarios. These changes focus on the load at risk criteria in the licence conditions with some other changes to specific requirements. The reliability improvement scenario maintains the existing criteria, but requires compliance to a more onerous maximum demand forecast.

9.1.1 Reliability reduction scenarios

Materiality of schedule

Across all three DNSPs, Schedule 1 is the most significant part of the licence conditions with regard to capex requirements. Essential is the only DNSP that is anticipating significant levels of capex associated the other schedules, namely Schedule 3.

This finding is in line with our understanding of the driver of the DNSPs' recent capex, and the driver we would expect in the future. As such, changes to this schedule should be an important focus for the AEMC's investigations.

All that said, it is also our understanding that a significant proportion of the capex increases that have occurred in the current period are largely due to the “catch-up” effect of achieving compliance to the existing schedule by 2014. As such, irrespective of whether this schedule is changed (at least to weaken reliability), we would expect a reduction in forecast expenditure from recent levels.

Reasonableness of forecasts

Based upon our methodology review, we have not found significant cause to say that the DNSP's capex forecasts associated with Schedule 1 are not reasonable for the purposes required here. However, we have greater concerns with the reliability forecasts. In this regard, we consider that the methodologies applied by the DNSPs to calculate expected energy not served associated with the distribution network may overstate this measure by a significant amount.

It is noted that the DNSPs have only accounted for our proposed changes to the load at risk parameters (as it relates to the relevant security level) within their forecasting. The DNSPs also tended to focus on the N-1 criteria, rather than the normal criteria[13]. The following specific changes did not appear to be explicitly analysed by any DNSPs:

- the increase to the existing urban/nonurban 10 MVA break point (15 MVA for Essential) associated with sub-transmission lines and zone substations (and the associated change to the security level of non-urban sub-transmission substations), which was applied to Scenario 2 and Scenario 3
- the removal of existing clauses associated with the requirement to load urban distribution feeders no greater than 80% by 2014 and 75% by 2019, which effected all three scenarios.

Given that the change to the allowed level of N-1 load at risk should be the primary factor driving compliance, we consider that the simplifications and omissions were reasonable given the time available to prepare the forecasts.

Comments on the proposed changes to Schedule 1

The following are some further points on the specific changes to the licence conditions that we consider may be helpful to the AEMC (and NSW government) deliberations.

- Although all the specific changes to Schedule 1 may not have been modelled in detail, we still consider that the set of changes in each scenario can be considered together. The only exception to this would be the changes associated with the 10 MVA limit on when radial sub-transmission arrangements are appropriate (the first dot point above). Our concern here is that, for specific substations or lines, the level of expected energy not served from this change may be significantly greater than that suggested by the analysis provided by the DNSPs. This may be particularly significant for the more extreme reliability-reduction scenarios, Scenario 2 and Scenario 3. Therefore, on reflection, we consider that the increase to the existing 10 MVA break point should be omitted from the these scenarios. The change permitting radial arrangements for sub-transmission substations loaded below the existing break point can remain however.

[13] Given that, in most circumstances, the N-1 criteria will be exceeded prior to criteria associated with normal conditions.

- Our analysis of the capex and reliability forecasts suggest that the changes to Schedule 1 associated with the CBD network may not result in any significant changes in capex or reliability in the short to medium terms (i.e. over the next 10 years). This does not appear to be due to the changes being ineffective, in principle. Rather, it appears to be due to Ausgrid not forecasting significant compliance-driven projects associated with the CBD network over this period. This could suggest that these changes to the licence conditions could be omitted. However, in our view, before deciding to remove these changes, careful consideration would need to be given to the asymmetric nature of risks (to Ausgrid and customers) if the actual outcomes differ from the forecast.

- It is noted that the reliability results may suggest that the more extreme reliability reduction scenarios have positive net benefits. If this is the case then the scale of possible events and un-modelled risks may need to be carefully considered. An important point here is that for Scenario 2, and particularly Scenario 3, large levels of load at risk and energy at risk are being forecast. This is customer load that may need to be disconnected in order to protect assets (and possibly for safety reasons) should a fault occur around the time of peak demand. Although the probability of the event is small, and so, the expected energy not served in any year is small, should such an event occur, its consequence would be large. As such, it may be that some consideration to the maximum event size could be considered in deciding on the most appropriate scenario. For example, this could define the maximum size in terms of customer numbers, or minutes, or energy not supplied. Determining such an event may however require careful consideration and analysis to ensure that sub-optimal criteria are not defined that effectively supersede the load at risk criteria.

- Related to the point above, there would be other consequences to managing the network with increasing levels of load at risk. Our changes in each scenario allow for load at risk at both the distribution and sub-transmission level. One consequence of this will be less capacity available in the distribution network to cover sub-transmission outages. This could result in some further reduction in reliability (or even increased operational costs). For example, this may result in shorter durations being available to take planned outages; it may also require a greater operational focus on contingency plans and fault response to mitigate the consequences of an outage. The modelling undertaken by the DNSPs does not appear to have tried to analyse in any detail the overall effects of this.

  We would however consider that these effects must be second order compared to the forecasts presented. Therefore, in the absence of specific analysis to the contrary, we still consider that the allowance for load at risk on both distribution and sub-transmission networks can be considered together. Importantly, the licence conditions are effectively minimum standards; therefore, in circumstances where it can be shown to be economical to build in additional capacity then that is acceptable. It is also worth noting that we understand these matters appear to have been dealt with quite successfully by the Victorian DNSPs, who have operated with significant levels of load at risk historically.

- During discussions, some DNSPs have also expressed a desire that if increasing levels of load at risk are prescribed then there should be more prescription on the applicable equipment ratings that should be used to test compliance. It has been noted during this review that, even for the existing licence conditions, the DNSPs appear to interpret them differently with regard to the applicable ratings to test compliance.

  Nonetheless, in our view, we do not see a clear case that the definition of ratings in the licence condition should prescribe a methodology for its derivation in a technical way. Calculating ratings is not trivial, and there is the necessity to balance risks with regard to the rating adopted. As such, if not defined appropriately, further conservatism could be build into planning and operating decisions. We believe that DNSPs should be given some responsibility for assessing the most appropriate rating and accepting the risk of that decision. Prudency and efficiency matters associated with this can still be considered by the AER when determining revenue requirements. The current definitions in the licence conditions appear to be in line with this view. That said, this issue may need to be given more careful consideration.

9.1.2 Reliability improvement scenario

Schedule 1 also appears to be the most significant schedule in terms of the capex change associated with the reliability improvement scenario. However, greater care is required in interpreting and evaluating the forecast, as there are a number of issues associated with the DNSPs forecasts, as follows:

- Ausgrid's forecast does not include some capex that Ausgrid considers would be advanced to before 2014 if the changes in this scenario were applied. This results in the reported capex change understating the total increase in capex due to the scenario. Ausgrid has advised that it has calculated that an additional $142 million would be required prior to 2014. It is not clear if a similar issue may be affecting the reported reliability improvement; however, this difference is less likely to be material on the overall reliability change.
- Endeavour has not provided a forecast for urban distribution feeders (capex or reliability). Endeavour has also calculated the reliability change associated with sub-transmission incorrectly. This is resulting in an apparent increase in the expected energy not served from the base case, when a reduction should occur.
- Essential has not provided a forecast for any network categories (capex or reliability).

The other schedules appear to be far more significant with regard to the reliability improvement associated with this scenario. Therefore, care would be needed in assessing overall changes in aggregate. In our view, keeping the existing criteria, but moving to a 10% PoE maximum demand forecast – as defined in this scenario – would result in design planning criteria that are significantly more onerous than those adopted in other NEM states. As such, there would need to be a fairly compelling economic argument to adopt this scenario.

9.2 Schedule 3 – individual feeder standards

For Schedule 3, we proposed two changes to the licence conditions: a change to the standards; and the introduction of a cap on the number of non-compliant feeders to address each year.

9.2.1 Reliability reduction scenarios

Materiality of the schedule

As noted above, Essential is the only DNSP that is anticipating significant levels of capex associated with Schedule 3. This finding is expected for Essential as it has a very large proportion of short and long rural feeders, and as such, it would be expected that capex would be more significantly driven by poor performing feeders.

The reduction in capex is particularly significant in Scenarios 2 and 3, when the application of the cap has a significant effect on reducing the number of feeders to be addressed each year (Essential is the only DNSP that is affected by the cap).

Both Essential and Ausgrid are forecasting that the proposed changes to this schedule will affect reliability significantly (for Ausgrid, this only applies to Scenarios 2 and 3).

Reasonableness of forecast

Based upon our methodology review, we have not found significant cause to say that the DNSPs' capex and reliability forecasts associated with Schedule 3 are not reasonable for the purposes required here.

We have some minor concerns over the reasonableness of Essential's forecast, particularly with regard to the high number of new non-compliant feeders it is forecasting to find over the study period. The interaction of this feeder forecast with the introduction of the cap has had a significant effect, particularly on reliability, in Scenarios 2 and 3. For these two scenarios, the number of new non-compliant feeders that Essential is anticipating to find each year is significantly higher than the proposed cap. As such, the number of non-compliant feeders, not being addressed, escalates through the study period, resulting in an escalating level of expected unserved energy.

In proposing the cap, it had been assumed by us that the number of new non-compliant feeders a DNSP would find each year would be well below the cap. The cap was only intended to slow down the rate that the existing population of non-compliant feeders would be addressed.

Given the highly rural nature of Essential's network, we have tentatively accepted Essential's forecast.

Comments on the proposed changes to Schedule 3

The following are some further points on the specific changes to the licence conditions that we consider may be helpful to the AEMC (and NSW government) deliberations.

- Although we have accepted the Essential forecasts, we consider that it may be overstating the number of new feeders it will continue to find over the whole study period. As such, care may be needed if capex and reliability changes over the medium to long terms (i.e. 5- to 15-year period) are significant drivers of the benefits of the changes.

- Given Essential is the only DNSP that the cap has affected and it has had a far more deleterious effect than we anticipated, we believe that the AEMC should consider removing this proposed change from the scenarios. Essential has provided some analysis showing the effect of this removal on its capex and reliability forecasts. The table below shows the impact of this change over the study period.

  As expected, these results suggest that the removal of the cap will result in a significant reduction in the expected energy not served for both scenarios. However, for Scenario 2, this occurs at the expense of only a modest reduction in capex over the 15-year study period. Scenario 3 appears to suggest a more significant reduction in capex will be achieved, without such a significant increase in the expected energy not supplied.

Table 14 – Essential impact of removing Schedule 3 cap

Scenario	Capex change		Reliability change (EENS)	
	Original	Revised	Original	Revised
Scenario 2	$376 million	$78 million	5.0 GWhr	1.1 GWhr
Scenario 3	$556 million	$222 million	5.5 GWhr	1.9 GWhr

- For Ausgrid, the significant effect on reliability occurs because Ausgrid considers that the works to address poor performing feeders will affect overall reliability. As far as we can tell, the difference here to Essential is that Ausgrid is not assuming these are new non-compliant feeders – occurring because of the degradation of the network. Instead, they are part of the population of existing non-compliant feeders that have contributed to past performance.

  This means that as we progress through the study period, the works to address Schedule 3 can improve overall reliability considerably. It is difficult in a review of this form to determine how accurate this finding is over the whole study period. However, assuming that at least a good proportion of the works to address non-compliance to Schedule 3 does indeed improve overall reliability then it appears that there is scope for interaction between the standards in Schedule 2 and Schedule 3, and the AER's service incentive scheme. The implications of this may need to be given further consideration in deciding what the most appropriate standards should be, what the mechanism may be to achieve this, and whether some additional criteria in the licence conditions may need to be defined. Further issues associated with the potential interaction with Schedule 2 are discussed below.

9.2.2 Reliability improvement scenario

Essential is the only DNSP that is anticipating significant levels of capex associated with Schedule 3. All DNSPs however are forecasting that the proposed changes to this schedule will have a more significant effect on reliability. All changes relate to the proposed improvement to the standards – the cap has not affected any DNSP forecasts.

The issue noted above about the correction of poor performing feeders affecting overall reliability is potentially most relevant to this scenario, particularly for Ausgrid. In this regard, should this scenario be found to have net positive benefits, based upon the forecasts presented here, then careful consideration will need to be given to the best mechanism to drive a change that fairly balances the risk associated with actual outcomes being different. For example, the use of the AER's service incentive scheme may well be a more appropriate mechanism to drive the benefits for Ausgrid, should they actually exist.

9.3 Schedule 2 – reliability standards

For Schedule 2, we proposed the specification of a confidence level that the existing standards would be complied with.

Materiality of the schedule

For the three reliability reduction scenarios, Ausgrid[14] is the only DNSP forecasting capex and reliability changes due to the Schedule 2 changes. The capex change however is almost immaterial across all three scenarios, being no more than 1% of the overall capex change[15].

For the reliability improvement scenario, both Ausgrid and Essential are forecasting capex and reliability changes. For Essential, the capex change is relatively immaterial, but for Ausgrid it is a significant portion of the over change for this scenario. The reliability change is more significant, particularly for Ausgrid where it represents the majority of the change in reliability associated with this scenario.

Reasonableness of forecast

Ausgrid and Essential have used a similar approach to determine compliance with the changed licence conditions. At a high-level, we have accepted these approaches. However, there are critical differences in assumptions that we believe may be affecting the accuracy of the results of the reliability improvement scenario:

[14] For the results presented in this report, we have corrected an error in Ausgrid's forecasts. Ausgrid has tentatively accepted this correction; however, a revised template has not been formally resubmitted.
[15] The reliability change appears more significant in Scenario 1, but this is because the other two schedules are contributing little reliability change.

- For Ausgrid, it has used historical costs to determine future capex. For the reliability improvement scenario, it is forecasting the need for some significant reliability improvements. These historical costs are probably satisfactory for small reliability improvements. However, in our view, it is likely that it will be increasingly costly to achieve the more significant reliability improvements predicted by Ausgrid for the reliability improvement scenario. In this regard, we believe Ausgrid may be understating the capex change associated with this scenario. We believe this would be material; it is not possible to say to what degree.
- For Essential, it has not carried the reliability improvement forward through the study period. As such, we believe that Essential is understating the reliability improvement over the study period.

Comments on the proposed changes to Schedule 2

The following are some further points on the specific changes to the licence conditions that we consider may be helpful to the AEMC (and NSW government) deliberations.

- An issue the AEMC may need to consider relates to the impact that Schedule 1 and Schedule 3 may have on the forecast reliability in any year. The expected energy not served resulting from the load at risk parameter associated with Schedule 1 can lead to lumpy changes in the expected or actual reliability in any year. Depending on the nature of individual network components, this may rise over a short period as energy at risk builds up, but then disappears when the relieving project is undertaken. Furthermore, as discussed above on Schedule 3, works undertaken to address non-compliance to Schedule 3 could improve overall reliability in some circumstances. As such, capex to address a Schedule 2 reliability gap in one year could end up being stranded in a later year due to the effects of projects undertaken to comply with Schedule 1 and Schedule 3.

  To achieve a more optimal outcome, the AEMC could consider adding some additional wording associated with Schedule 2 to ensure that works undertaken to comply with Schedule 2 are economic over the medium term. For example, this would require the DNSPs to have regard to the future effects of Schedule 1 and 3 to ensure that Schedule 2 compliance works in the short-term were not superseded (i.e. effectively stranded) by future actions to ensure compliance to Schedules 1 and 3.
- Particularly in the case of Ausgrid, for the reliability improvement scenario, there are significant improvements in reliability for modest increases in capex. However, as noted above, there is some uncertainty as to what the actual cost would be to achieve such improvements. If the reliability improvement scenario is showing a significant net benefit due to the changes associated with this schedule, then we believe it will be important to consider other mechanisms to achieve a reliability improvement, which can provide a better balance of the risks associated with outcomes being different from these forecasts. As noted above for Schedule 3, the AER’s service incentive scheme appears to be a far more appropriate mechanism to

achieve the types of overall reliability improvement that changes to Schedule 2 would achieve.

A Explanation of load at risk and associated measures

Load at risk is an important concept in our suggested changes to the design planning criteria of Schedule 1. This concept concerns the possibility of interrupting customer's load.

Load at risk and its related terms can have different interpretations. Therefore, this appendix provides an explanation of what we mean by these terms and how they could be determined. For demonstration purposes, this section focuses on substations and N-1 conditions. The discussion however is equally relevant to lines and N-2 and above conditions.

It is important to note that this section has been written as a high-level guide for a non-technical reader. Consequently, much of the nuance and complexity associated with each term has not been covered.

Asset ratings: normal and N-1 ratings

The rating of an asset defines its maximum permitted loading under particular circumstances. Operating the asset above that rating can damage the asset and incur safety risks. Assets therefore are not generally permitted to operate above such a rating. If this is likely to occur (or does occur) then the load may need to be transferred away from that asset. In extreme circumstances, this will require the supply to customers to be interrupted.

Importantly, the rating of an asset can differ depending on the circumstances. For planning purposes, the relevant rating will often reflect the security level and likely worst-case conditions associated with the security level.

For example, consider a substation with three parallel transformers. Each transformer may have a rating that reflects its normal operation: its normal rating[16]. This rating specifies the maximum permissible loading that the transformer can carry. The normal rating of the substations will generally reflect the summation of the normal ratings of the three transformers.

The N-1 security level concerns the condition when one of the transformers is removed from service due to an unexpected event (e.g. its failure). The N-1 rating of the substation will therefore reflect the worst-case combination of only having two transformers in service. Often this N-1 rating is called the firm or emergency rating of the substation, depending on the circumstances.

[16] For transformers, this rating will normally be calculated to allow for the typical load cycle – often referred to as its normal cyclic rating.

This N-1 rating reflects the maximum permissible loading that the substation can carry such that if a single failure of a transformer occurred then the remaining transformer(s) would be within their ratings. Importantly, different operating conditions may be assumed for these circumstances, and as such, the N-1 rating may reflect this.

The concept of load at risk

For strict N-1 planning criteria, the substation would be non-compliant when the peak loading reaches the N-1 rating. This point would signify the time that some action (e.g. network augmentation) would be required to be taken by the DNSP to ensure that the peak loading did not exceed this N-1 rating. For many network components, planned to strict N-1 criteria, this loading would be well below their normal rating. Therefore, there would be an amount of redundant capacity in the system that is only there to cater for the N-1 event[17].

The concept of *load at risk* reflects the situation when the substation is loaded above its N-1 rating (or N-2 rating, if that is the relevant security level). The *load at risk* represents the amount of load that is above the N-1 rating. Using the example above, the *load at risk* is the amount of load that may need to be interrupted to ensure that the substation does not exceed its N-1 rating if a single transformer fails.

Allowing the assets to operate with some *load at risk* enables some of the redundant capacity to be used, under normal circumstances. But this additional efficiency in asset utilisation is traded off against the risk that customer load may need to be interrupted under certain situations.

As the probability that such a network outage will occur at a time when actual load is above the N-1 rating is often small, it can be nonetheless economically efficient to operate with some level of *load at risk*.

Planning criteria associated with load at risk, energy at risk, and time at risk

The above has introduced the broad concept of *load at risk*. For deterministic planning criteria, such as those in Schedule 1, three related parameters can be used to specify the maximum level of *load at risk* that is allowed:

- ***Load at risk*** – As discussed above, *load at risk* is the amount of demand (i.e. electrical power) above the N-1 rating. The associated planning criteria would be specified as the maximum amount of *load at risk* that could occur in a year (i.e. the maximum demand permitted on the asset minus its N-1 rating). These criteria could be specified in absolute terms (e.g. kW, MW, etc) or as a percentage of the N-1 rating (e.g. a 10% load at risk criteria would mean that an asset could be loaded to 110% of its N-1 rating).
- ***Energy at risk*** – The *energy at risk* is the total amount of energy (i.e. kWhr, MWhr, etc) associated with any load that is at risk over a period (normally a year). Similar to the *load at risk* criteria, this criteria could be specified in absolute terms (e.g.

[17] It is worth noting that there can be circumstances when the N-1 rating of a substation is very near, or even above, its normal rating. In these cases, exceeding the normal rating may be the more limiting factor driving the need for an augmentation.

kWhr, MWhr, etc) or as a percentage of the total energy carried by the asset over the period.

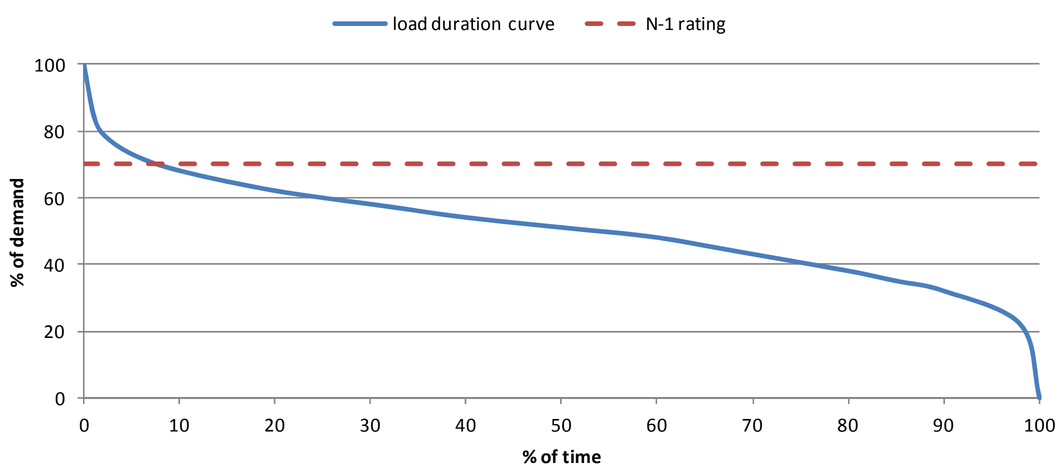
- ***Time at risk*** - The *time at risk* is the total amount of time, over the period, that load will be at risk (i.e. the total amount of time that the load will be above the N-1 rating). A planning criteria associated with this parameter would express the maximum amount of time that load can be at risk over a set period (normally a year).

Obviously, the demand varies constantly over time, reflecting daily and seasonal fluctuations in the consumption of electricity by customers. Therefore, to calculate the above three terms (e.g. to test compliance to the planning criteria) requires an assessment of this load profile against the N-1 rating.

To simplify this task, a *load duration curve* is often used. The *load duration curve* is simply a plot of the length of time over the period that the actual demand is above a certain amount.

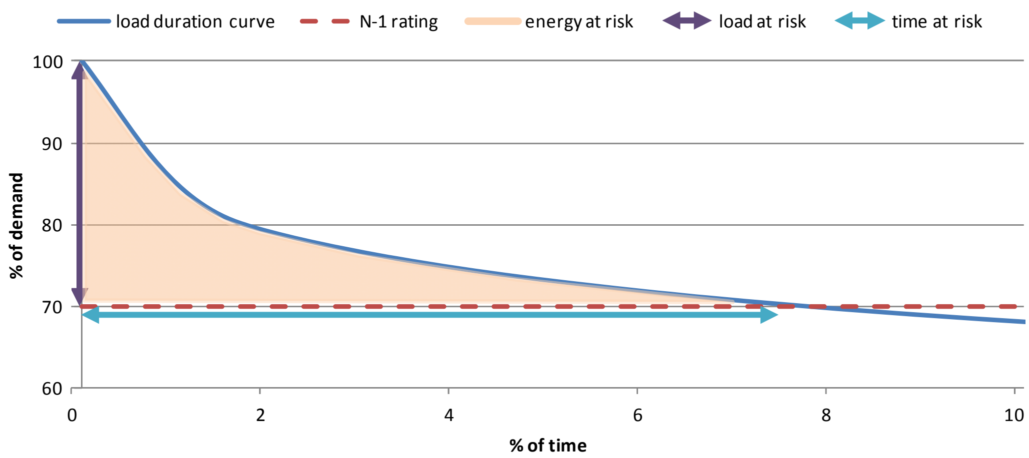
Using such a *load duration curve* and knowledge of the N-1 rating, the above three parameters can be estimated as shown in the figures below. Figure 28 shows a typical *load duration curve* (represented as a percentage of the maximum demand). For example, the demand is above 60% of the maximum demand for approximately 25% of the time. The red dashed line represents an assumed N-1 rating. Clearly, from this diagram, the asset associated with this *load duration curve* operates above its N-1 rating for a period, and as such, there will be *load at risk* for the N-1 security level.

Figure 28 – typical load duration curve and N-1 rating



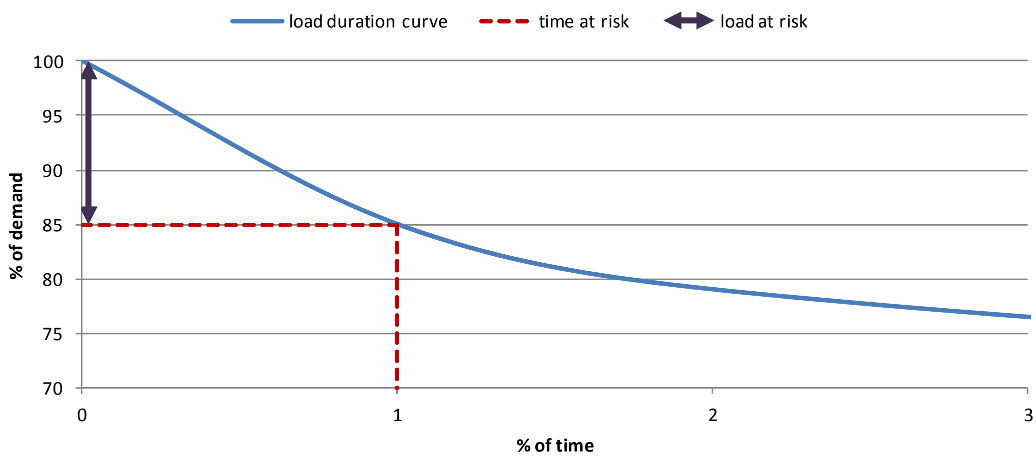
As *load at risk* is associated with the peak demand conditions and occurs for a short period, Figure 29 shows the same *load duration curve* but focused on this peak period. The *load at risk* is read from the y-axis, and shown by the purple line. In this case, approximately 30% of the maximum demand is at risk of needing to be interrupted for an N-1 event. The *energy at risk* is the area between the N-1 rating and *load duration curve*, shown by the orange region. In this case, although the *load at risk* is 30% of the maximum demand, the *energy at risk* is less than 1% of the total energy delivered by that asset. This significantly reduced level of *energy at risk* compared to the amount of *load at risk* is typical of the types of peaky load that are common in the NEM. This is the reason that significant levels of *load at risk* can often be tolerated without affecting the amount of interrupted load (or reliability) significantly. The *time at risk* is simply measured from the x-axis, based upon the percentage of time that the *load duration curve* is above the N-1 rating. In this example, it is approximately 7.5% of the time. Assuming the period over which the *load duration curve* has been calculated is a year then this implies that the asset will be operating with load that is at risk of being interrupted due to an N-1 event for just over 27 days in a year.

Figure 29 – typical load duration curve and load at risk measures



In the licence condition changes we have suggested, we have used a combination of maximum *time at risk* and maximum *load at risk* criteria. To plan to the *time at risk* criteria, the maximum permissible loading must be calculated. This is most simply done using the *load duration curve*. For example, Figure 30 shows how the maximum permissible loading can be calculated from the existing planning criteria, which allows zone substations to have *load at risk* for 1% of the time (i.e. the maximum *time at risk* is 1%). This shows the level of demand (85%) that coincides with the 1% *time at risk* criteria. This 85% demand level must equal the N-1 rating, and therefore, the maximum permissible loading is the proportion above this point (which would equal N-1 rating / 85% for this example).

Figure 30 – calculating maximum permissible loading from *time at risk* criteria



Calculating expected energy not served

The above has shown how *load at risk*, *energy at risk* and *time at risk* can be calculated from *load duration curves*, and how these parameters can be used to define maximum permissible loading levels for planning purposes. These concepts are sufficient to plan to the existing licence conditions and the changes proposed in this report under a purely deterministic planning framework.

The parameters however do not provide an explicit reliability measure. To evaluate the scenarios, the AEMC needs a measure of reliability. To do this, we need to determine the average amount of energy that we could expect not to be supplied to customers in each year due to the *load at risk* planning criteria. This value is called the *expected energy not served*.

The *expected energy not served* is the integral over the year of the *load at risk* at any point in time multiplied by the probability that the system is in the relevant insecure state at that time. Noting the discussion above on the *load duration curve*, this can be approximated by the *energy at risk* (as calculated above) multiplied by the probability of being in that insecure state[18].

Using the above example of the substation with three transformers, assume:

- the unanticipated major failure of a transformer is a 1 in 100 year event
- and, if a transformer has a major failure, it will be out of service for 3 months.

The average annual unavailability of that transformer would be 1/100 x 3/12 = 0.25% of time (i.e. on average, the transformer will be unavailable 21.9 hours in a year). As there are three transformers in the substation then the probability that the substation could be in the N-1 state is 3 x 0.25% = 0.75% (i.e. on average, the substation will be in the N-1 states for 65.7 hours in a year)[19].

[18] This assumes the probability of being in that state is largely independent of the loading.
[19] The probability of higher order outages (e.g. two coincident outages) is assumed immaterial here.

Now assume the maximum demand on the substation is 100 MW and the total energy delivered by the substation over a year is 438 GWhr. Then, using the parameters defined above (Figure 29), the energy at risk is approximately 2.2 GWhr. Therefore, the *expected energy not served* associated with the N-1 condition is 16.4 MWhr.

B Summary of forecasting methodologies

This appendix provides a summary of our understanding of the various methodologies that have been applied by the DNSPs to prepare their expenditure and reliability forecasts.

This summary is based upon the various documents, models and work examples that have been provided by the DNSPs to support their forecasts. It also includes our understandings based upon discussions with the DNSPs and the project secondments to the AEMC.

The intention of this appendix is not to provide a detailed description of the methodologies applied, input data and assumptions. Instead, it is only to highlight the key methodological points in order to aid in the appreciation of matters raised in the main body of this report.

The explanations provided should not be read as our acceptance or otherwise of the appropriateness of the methodologies. This matter is discussed in Section 8 in the main body of this report.

B.1. Ausgrid

B.1.1. Schedule 1 forecasting

The forecasting methodologies can be considered in terms of Ausgrid's sub-transmission network and distribution network.

Sub-transmission capex

The sub-transmission capex forecast is based upon a bottom-up analysis of future non-compliance events and the projects required to regain compliance. This process relies upon individual project plans prepared as part of Ausgrid's normal planning practices.

This planning process produces a 20-year plan of individual projects (including project cost estimates) that will address forecast breaches of the existing licence conditions.

The process to develop these compliance related projects involves the following at an individual substations and line level:

- The maximum permissible loading associated with the relevant licence condition is determined, based upon the firm rating of the network component and the allowed level of load at risk defined in the licence condition. This calculation makes use of the relevant load duration curve, as explained in Appendix A.

- The forecast peak loading of the substation gives an initial indication of future non-compliance. From this knowledge, permanent load transfers between adjacent substations are determined to relieve the compliance issues.
- Allowing for these load transfers, the timing of non-compliance is then assessed to determine a project need.
- Individual sub-transmission projects to address this non-compliance are then scoped and costed.

The above process integrates with other considerations, most notably the condition of the assets and the associated replacement plan.

The base-case forecast simply reflects the set of projects, their costs and timings that result from this process.

One significant modification of the output of this process has been applied to derive the capex in the last 5-years of our study period. This modification was applied to address the "lumpy" nature of expenditure, which suggested a low level of capex during that period. Ausgrid did not consider that this was likely to reflect actual capex, as expenditure on some of the major projects would need to be incurred earlier than indicated. As such, for this study, capex forecast in the last year of our study period was defined as the total forecast over the 3-year period from 2028/29 to 2030/31.

To assess the changes to capex for each scenario, Ausgrid has reassessed the timing of individual planned projects under the proposed changes to the licence conditions. Generally, project scopes and costs have been left unchanged.

This analysis has largely focused on recalculating maximum permissible loading, allowing for load at risk parameters in the licence condition scenario. In this way, the revised timing can be determined from when the network component forecast loading will exceed this changed maximum loading.

Due to the limited time available, Ausgrid has had to use engineering judgement at times to assess to what extent a project may be deferred. This judgment is most notable when considering the impact that the planned permanent load transfers will have on the loading of the substations. In this regard, the time when a substation will be non-compliant under a scenario depends on how much load can be transferred to or from other substations in order to ensure that they too are compliant. As this is assessed under the base case, this effect needs to be accounted for the various options.

For the improvement scenario (Scenario 4), the above process was applied assuming the peak loading was increased to reflect the percentage increase in maximum from the 50% PoE forecast to the 10% PoE forecast. This increase was estimated to be 6.14% by Ausgrid, based upon a sample of zone substation forecasts.

It is also important to note that where costs are estimated to undertake the planned load transfers using distribution level augmentations, these costs have been allocated to the distribution expenditure categories for reporting purposes for this study.

Sub-transmission reliability

The sub-transmission reliability forecast has been determined in terms of the increases in the expected energy not supplied associated with each scenario.

As a first step in this estimate, Ausgrid has calculated the level of energy at risk at individual network components (i.e. substations). This calculation uses the forecast demand, the firm rating, and relevant load duration curve, to determine the energy at risk in line with the explanation given in Appendix A.

Ausgrid has only assessed the substations and associated planned projects that it considers will reflect significant changes to reliability. This means that projects that are common to all options are excluded, including replacement projects.

Ausgrid has also not estimated reliability impacts associated with feeders exceeding their firm rating. In Ausgrid's view, to assess these issues would require significant effort that was not feasible in the time available. This may mean that the estimates may understate the expected energy not served. However, as only a small percentage of the projects were driven by feeder issues, Ausgrid does not consider that this should be material.

To determine the expected energy not supplied for N-1 conditions, Ausgrid has derived an average probability of unavailability of 1.36%. This is an average probability that it has applied across all its substations. This probability was derived through a network reliability-modelling tool that Ausgrid uses. This tool holds the network configuration and individual asset failure rates and durations. The tool was used to provide probabilities across a sample of locations[20].

This probability is then multiplied directly with the energy at risk calculated for each substation to determine the expected energy not served for that substation. Individual substations are then summed to develop the total forecast.

As far as we are aware, the calculations have allowed for planned projects alleviating energy at risk following their commissioning.

Distribution capex

Ausgrid's approach to calculate distribution capex does not rely upon detailed bottom-up forecasts of planned projects. Instead, high-level techniques have been used.

These techniques differ between the CBD and non-CBD distribution networks.

For the non-CBD distribution network, a high-level feeder modelling approach has been used. We understand that this model has been developed by Ausgrid, and is used internally to prepare medium to long-term forecasts of distribution needs.

To perform this task, the model does not attempt to assess actual feeders and specific needs. Instead, the model uses actual network data to determine a typical distribution network arrangement at the zonal level. Feeder demand forecasts are then used to

[20] As we understand it, the tool only provided probabilities for N-2 and worse conditions. Therefore, this output was squared to estimate the equivalent N-1 availability as this was considered the most significant condition for these studies.

determine when overloads would occur on this typical feeder, under N-1 conditions. In this way, the model forecasts aggregate volumes of new feeders and feeder length.

It then uses cost-functions that map new feeder installation costs per length installed (i.e. $ per km) to a load density metric. These cost-functions are used to determine the capex from the volume forecasts, based upon the relevant load density. The cost-functions have been determined from a set of historical projects, covering the past 3-year period (approximately 400 projects).

This model predicts the need for new feeders, based upon the timing when strict N-1 compliance would not be met. To allow for the load at risk parameters in the licence conditions, the feeder ratings, which are an input into the model, have been adjusted up to reflect the additional load that can be carried (under the load at risk parameter) before non-compliance would occur. This adjustment is in line with the methodology Ausgrid has used to determine the similar maximum permissible loading for sub-transmission network components. The value used was calculated by averaging the percentage increase that was deduced from a sample of feeders.

For scenario 4 (the improvement scenario), the feeder ratings have been scaled down by the percentage difference between the 50% and 10% PoE maximum demand forecasts. This difference was calculated as 6.14% by Ausgrid, which aligns with the amount noted above for the similar sub-transmission adjustment.

The capex that is directly output from this model has been adjusted to generate the forecast for this study. This adjustment is to allow for situations where the N security level licence conditions (i.e. operation under normal circumstances) may be exceeded prior to the N-1 licence conditions.

This adjustment has been applied to the three scenarios where a weakening of the licence conditions has occurred. This adjustment involved halving the capex reduction deduced directly from the model for the base case, and then increasing the resultant amount by 5% each year over 10 years up to a limit of 50%. We understand that the basis of the 50% limit is past experience of the Hunter Valley feeders, where Ausgrid considered that, when heavily loaded, approximately 50% of the feeders needed to be augmented due to their loading exceeding the rating under normal conditions.

For the CBD network, a much simpler approach has been applied. The capex forecast is simply based upon the approximate historical level of capex Ausgrid has incurred to rectify constraints on the CBD distribution network.

Distribution reliability

In a similar vain to the capex forecast, Ausgrid has not calculated the expected energy not supplied at an individual feeder level. Instead, the estimate is based upon analysis of an average urban[21] and CBD feeder under N-1 conditions.

[21] The urban group also includes non-urban feeders, as the population of non-urban feeders was considered too small to analyse separately.

The energy at risk for the average feeder is calculated from the average feeder loading, typical feeder ratings, and average load profile (i.e. load duration curve). For each scenario, this calculation estimates the level of load associated with the load at risk parameter for that scenario[22]. Energy at risk is then approximated from this level of load, using a triangle approximation to represent the area under the load duration curve.

The total energy at risk for the network is then determined by multiplying the energy at risk for the average feeder by the number of feeders predicted by that scenario.

To determine the expected energy not supplied, the N-1 outage probability has been calculated from the 5-year average of the most recent historical outage data. This data has been used to determine the average outage frequency and outage duration[23]. This average historical outage probability is then adjusted for each year in the study period to account for the number of feeders predicted for each scenario.

This probability is then multiplied directly with the total energy at risk to determine the expected energy not served.

B.1.2. Schedule 2 forecasting

To assess future non-compliance to Schedule 2, Ausgrid has used statistical analysis of its historical performance to assess the probability density function for the reliability of each feeder category. The results of this analysis allow the confidence levels in the existing reliability to be defined.

Future reliability is then forecast for each feeder category and scenario, accounting for the following factors:

- the forecast increase in customer numbers, which affects the number of customers and customer minutes per outage
- the effects of Schedule 1, including the expected unserved energy due to the load at risk parameters, and the reliability impact through the change in the number of feeders
- the effects of Schedule 3.

These factors are compound year-by-year and the resulting forecast is assessed to determine whether there would be a "gap" between this forecast and the reliability required to ensure compliance to the confidence level defined for each scenario[24].

If such a gap exists, the capex forecast to address the gap is calculated based upon the 4-year average of reliability works (i.e. cost per customer minute of improvement) in each feeder category.

[22] For example, for urban feeders the proportion of load associated with 0.5% of time load at risk parameter (scenario 1) is approximately 15%. This percentage is multiplied by the average feeder loading to determine the load at risk for the average feeder.
[23] The CBD probability is based upon the urban outage rates, as suitable data was not available.
[24] For the base-case, a confidence level of 95% is assumed.

It is worth noting that this analysis is used to determine the overall reliability. In this regard, the overall reliability does not reconcile with the summation through the individual tables mainly due to the compounding that is applied.

A further factor is the adjustment to account for the effect of the additional distribution. Although this effect appears to be related to Schedule 1 obligations, it has not been allocated to Schedule 1.

B.1.3. Schedule 3 forecasting

The capex and reliability forecasts are based upon a forecast of the number of feeders that will exceed the licence conditions in each year of the study period.

The base-case non-compliant feeder forecast is based upon the historical number of feeders that have exceeded the licence conditions and an assumption on how this number will reduce during the study period. This assumption reflects Ausgrid's view that the number will decline as fewer poor performing feeders remain in the population. The assumptions applied for the various feeder categories are as follows:

- CBD – no decline assumed
- Urban – an exponential reduction based upon the historical decline
- Short rural – reduce by 1 feeder every 2 years.

Historical 4-year averages have been calculated for:

- the proportion of projects undertaken to address the number of feeders
- the cost per project
- the customer minute improvement achieved through these projects.

These parameters, with the non-compliant feeder forecast, are then used to calculate the base-case capex and reliability[25].

To assess the four scenarios, the change from the base-case capex and reliability forecasts is estimated as a similar proportional change as applied to the standard (i.e. a 10% reduction in the standard will result in a 10% reduction in the capex).

In undertaking this analysis, Ausgrid has assumed that the limit parameters in our scenarios will cap the number of projects to be performed in a year, not the number of non-compliant feeders. Based upon this assumption, Ausgrid has not found that this parameter affects the capex and reliability forecasts, as the number of projects forecast is always well below this limit.

It is important to note that the expected unserved energy provided in the Schedule 3 tables is derived from the customer minutes not supplied on all feeders exceeding the standard. This is different to the Schedule 3 effects that are brought into the Schedule 2 analysis discussed above. This amount relates to improvements in reliability that result from the projects undertaken due to these standards.

[25] Customer minutes are transformed to MWhrs using the conversion formula provided in the AEMC template.

B.2. Endeavour

B.2.1. Schedule 1 forecasting

The forecasting methodologies can be considered in terms of the sub-transmission network and distribution network.

Sub-transmission capex

The sub-transmission capex forecast is based upon a bottom-up analysis of future non-compliance events for individual network components (i.e. substations and lines). The analysis only focuses on the load at risk parameter within the licence conditions. The analysis makes use of a model prepared by Endeavour for long-term planning processes, which has been amended to undertake the scenario analysis for this study.

For each network component, the process to develop the forecasts of non-compliance is as follows:

- For each scenario, the maximum permissibly loading is determined, based upon the firm rating of the network component and the allowed level of load at risk defined in the licence condition. This calculation makes use of the relevant load duration curve for the network component - as explained in Appendix A.
- The forecast peak loading of the network component is then used to determine the timing of non-compliance, based upon the year that the peak loading will exceed the maximum permissible loading[26].

To derive a capex forecast from the forecast non-compliance events, the average project cost per non-compliant component is used - $17million per event. This average cost is determined from the set of compliance projects that Endeavour has planned for the last three years of the current regulatory period.

The process does not attempt to consolidate the forecast with other drivers, such as replacement. However, Endeavour considers that this impact should not be material.

Sub-transmission reliability

The sub-transmission reliability forecast has been determined in terms of the increases in the expected energy not supplied associated with each scenario. The model assesses each network component (i.e. substations and lines), and is based upon the model discussed above that is used to prepare the capex forecast.

For each network component, energy at risk is calculated from the level of load above the firm rating, using the relevant load duration curve. This calculation is in line with the explanation given in Appendix A. The model assumes that energy at risk will be zero following the time that non-compliance occurs (i.e. following the time that a capex project has been forecast).

[26] For the reliability improvement scenario (S4), the 10% PoE forecast is has been used.

To determine the expected energy not supplied for N-1 conditions, Endeavour has assumed typical major failure frequency and duration parameters for transformers and lines. These parameters assume:

- a major failure of a transformer is a 1 in 100 year event, with a duration of 2.6 months
- a major failure of a sub-transmission line is also a 1 in 100-year event, with an outage duration of 0.5 months.

The outage probability derived from these parameters is then multiplied directly with the total energy at risk to produce the total expected energy not supplied.

Distribution capex

The distribution capex forecast uses a model similar in principle to the sub-transmission model discussed above. The distribution model however has been prepared by Endeavour specifically for this study.

The distribution model undertakes a bottom-up analysis of future non-compliance events for individual feeders. Like the sub-transmission model, the analysis only focuses on the load at risk parameter within the licence conditions.

The model also only focuses on the forecast loading and firm rating of the initial trunk section of each feeder. For each scenario, the model calculates the maximum permissible loading for this feeder section, based upon the relevant load duration curve and load at risk parameter. The rationale here is in line with that applied for the sub-transmission model. An output of this model is the number of non-compliant feeders in each year of the study period.

To prepare a capex forecast from this output, an average project cost per non-compliant feeder is assumed. The average cost of $250,000 per non-compliant feeder has been derived from the historical number of non-compliant feeders and costs to augment these feeders over the 3-year period from 2008/09 to 2010/11.

Analysis for the improvement scenario (Scenario 4) has not been undertaken, as Endeavour did not have a 10% PoE maximum demand forecast at the distribution feeder level.

Distribution reliability

Endeavour has not calculated the expected energy not supplied at an individual feeder level. Instead, the estimate is based upon analysis of an average feeder under N-1 conditions.

The energy at risk over the study period for the average feeder is calculated from the average feeder's forecast loading, the typical feeder rating, and a typical load duration curve. The model assumes that energy at risk is capped at the level given by the relevant load at risk parameter. In effect, this assumption means that an augmentation returns the system to a "just" compliant state, rather than removing all load at risk.

The total energy at risk for the network is then determined by multiplying the energy at risk calculated for the average feeder by the number of feeders predicted by that scenario. To determine the number of new feeders, Endeavour has assumed that one new feeder will be added for every two non-compliant feeders.

To determine the expected energy not supplied, the N-1 outage probability has been calculated from current reliability data. This assumes that on average 0.68 faults per feeder will occur, with an average duration of 2 hours.

This probability is then multiplied directly with the total energy at risk to determine the expected energy not served.

B.2.2. Schedule 2 forecasting

Forecasts of capex and reliability associated with Schedule 2 have not been prepared. Endeavour considers that its performance with respect to Schedule 2 is currently significantly better than the targets (i.e. it already achieves a very high level of confidence of compliance, greater than the reliability improvement scenario). As such, it is not forecasting any expenditure to comply with the existing licence conditions over the study period. Moreover, it does not anticipate that any of the proposed changes will materially affect these requirements over the study period.

B.2.3. Schedule 3 forecasting

Due to the anticipated lower significance of the Schedule 3 changes on capex and reliability, Endeavour has used high-level analysis to prepare the forecasts.

The base-case capex forecast is simply assumed to be at the current level forecast for 2012/13. The reliability forecast is an estimate of expected energy not served of the various feeder categories, using typical feeder SAIFI and CAIDI parameters.

To assess the four scenarios, the change in the number of non-compliant feeders is estimated from the change in the standard. This number is used to calculate the change in capex, using historical costs per addressed feeder. The change in reliability is calculated based upon the historical improvements in feeder performance.

B.3. Essential

B.3.1. Schedule 1 forecasting

Essential is only anticipating two significant compliance-related projects on its sub-transmission network over the study period. It does not consider that the timing of these projects will change, other than for the worst-case scenario (Scenario 3). As such, it has not undertaken any significant modelling associated with its sub-transmission network. Furthermore, it has not explicitly modelled the reliability improvement scenario, as a 10% PoE forecast was not available.

The distribution capex forecast is based upon a bottom-up analysis of individual feeders. We understand that this model has been prepared by Essential specifically for this study.

The distribution model assesses future non-compliance events for individual feeders. The assessment focuses on the load at risk parameter within the licence conditions, and assesses both normal and N-1 conditions.

For each feeder, this model forecasts the feeder loading under normal and N-1 conditions. To undertake this analysis it uses various inputs, including the current feeder loading, the forecast per annum growth in loading, the feeder rating, the amount of back up required in each feeder to allow for N-1 conditions.

For each scenario and feeder, the model predicts the maximum permissible loading based upon the scenario's load at risk parameters and the relevant load duration curve for that feeder - as explained in Appendix A.

To prepare a capex forecast, a set of projects and costs have been assumed, based upon the forecast normal and N-1 utilisation of each feeder. The projects range from a $40,000 minor load transfer, assumed to occur when utilisation reaches 75% to a $910,000 new feeder project, assumed to occur when the N-1 utilisation exceeds 90% of the permissible loading.

Distribution reliability

The distribution feeder model described above is also used to calculate expected energy not served for each feeder and each scenario.

The rationale of these calculations is not completely clear and does not appear to follow the rationale described in Appendix A.

As we understand it, to undertake this analysis, an energy at risk measure[27], failure frequency and outage duration are input for each feeder. The energy at risk measure reflects the status of the current feeder and is calculated from the appropriate load duration curve for each feeder. An energy not served measure for each feeder is then calculated using this data[28]. To forecast expected energy not served in each year of the study period, the energy not served measure is scaled by the percentage difference in utilisation from the maximum permissible utilisation.

The model assumes that there is no load at risk after the loading exceeds the maximum permissible loading (i.e. following the major augmentation project). This analysis covers both normal and N-1 conditions.

The total expected energy not served for the base case and scenarios is the sum of all expected energy not served for all the feeders.

B.3.2. Schedule 2 forecasting

To assess future non-compliance to Schedule 2, Essential has used statistical analysis if its historical performance to assess the probability density function for the reliability of each feeder category. The results of this analysis allow the confidence levels that reliability would be achieved to be defined.

[27] The calculation appears to use an average hourly energy at risk measure, rather than the total energy at risk.
[28] This measure does not appear to be a simple expectation of energy not served.

The results of this modelling are used to determine whether there will be a "gap" between the standard in the licence condition and the actual reliability associated with the confidence level defined in each scenario[29].

Essential has found that the installation of additional reclosers is generally the most cost effective method of improving reliability. Therefore, if a gap is predicted, capex is forecast using a model that estimates the number of additional reclosers required to remove the gap. Essential assumes the average installation cost per recloser is $60,000, based upon historical project costs.

B.3.3. Schedule 3 forecasting

The capex and reliability forecasts are based upon a forecast of the number of feeders that will exceed the licence conditions in each year of the study period.

The base-case non-compliant feeder forecast is derived from the historical number of feeders that have recently exceeded the licence conditions. Essential considers that this recent number of non-compliant feeders should be reasonably representative of the number anticipated through the study period. Furthermore, the forecast number of these non-compliant feeders that will be addressed is based upon the historical proportion.

Therefore, for the base case, the capex forecast is based upon a continuation of the recent expenditure levels. The forecast is allocated to the feeder categories assuming historical patterns.

To allow for the scenarios, the forecast number of non-compliant feeders and feeders being addressed each year is adjusted based upon the two changes allowed for in the scenarios: the cap on the number of non-compliant feeders to be addressed each year and the change to the standard.

To allow for the change in standard, the historical number of feeders exceeding the changed standard is used to define the number of new feeders forecast each year. To allow for the cap parameters in the scenarios, any non-compliant feeders not addressed in a year, due to the operation of the cap, are assumed to be non-compliant feeders in the subsequent year. As such, if the cap constrains the number of feeders forecast to be addressed then the number of non-compliant feeders escalates each year. To ensure that this does not increase too high, an upper limit is assumed. This upper limit is set at a level that reflects the historical maximum number of poor performing feeders.

The capex for each of the scenarios is calculated as a simple scaling of the base-case capex, using the reduction in the number of non-compliant feeders forecast to be addressed in that year.

To forecast reliability, the average historical "gap" in reliability (i.e. customer minutes and unserved energy) per non-compliant feeder is calculated (i.e. the difference between the feeder reliability and the licence condition standard). This average historical "gap" is multiplied by the forecast number of non-compliant feeders to estimate the total expected energy not supplied in these noncompliant feeders.

[29] For the base-case, a confidence level of 95% is assumed.