Please note that sections with red background are Confidential in this document

Operating and capital expenditure ‘site visit’ clarifications

2015–19 Subsequent regulatory control period

3 October 2014

Contents

Overview

On 16 September 2014 officers from the AER and ActewAGL Distribution (AAD) met and discussed questions that the AER had in relation to operating expenditure (opex) and capital expenditure (capex).

The document responds directly to questions raised by the AER on 16 September, which were followed up in writing and received by AAD on 17 September (capex questions) and 23 September (opex questions).

PART 1

1. Operating expenditure

In order to address the specific questions raised in writing by the AER, ActewAGL Distribution's (AAD) first sets out integral concerns with the AER's benchmarking. This response sets out the factors that need to be incorporated into the benchmarking analysis to ensure comparability of opex, and reiterate the drivers of abnormal non-recurring opex in 2012/13 that are adversely impacting AER's analysis of the base year.

1.1 Benchmarking

At the 16 September meeting, AER officers stated that the AER plans to adjust ActewAGL Distribution's (AAD) base year operating expenditure on the basis of results contained in the AER's draft benchmarking analyses[1] circulated to distribution businesses in August. AAD is deeply concerned by these statements. At the 16 September meeting, AER officers stated that the AER plans to adjust ActewAGL Distribution's (AAD) base year operating expenditure on the basis of results contained in the AER's draft benchmarking analyses[2] circulated to distribution businesses in August. AAD is deeply concerned by these statements.

Firstly, AAD considers that any such adjustment would be a departure from the revealed cost method and would undermine incentive based regulation. Such an approach also reduces regulatory certainty which is necessary for longer term planning for DNSPs between regulatory periods.

Secondly, AAD does not consider that the AER's draft benchmarking analysis captures all the unique characteristics of different networks, especially capitalisation processes, leasing practices and and abnormal items. AAD encourages the AER to further review and evaluate AAD's responses to the AER's draft economic benchmarking and category analysis benchmarking reports on 22 and 29 August 2014 respectively as well as additional information provided in this response.

In its response to the AER's draft annual benchmarking report, AAD highlighted the weaknesses in the benchmarking approach and the modelling specifications that significantly undermine the legitimacy of the benchmarking results:

- The MTFP model is unstable and the results contained in the draft benchmarking report are not robust
- It suffers from a lack of comparable data

[1] The AER's draft category analysis benchmarking report and the draft annual benchmarking report.

[2] The AER's draft category analysis benchmarking report and the draft annual benchmarking report.

- The choice of input and output specifications disadvantage DNSPs that have a high proportion of their network at high voltage
- The benchmarking fails to normalise for individual circumstances, exogenous environmental factors and unique costs
- There was no Data Envelopment Analysis (DEA) undertaken by the AER to demonstrate the robustness of the MTFP model and its results, despite the AER stating it would do this in its expenditure forecast and assessment guidelines.

Similarly, the AER's draft category analysis benchmarking results fail to take into account individual network circumstances and neither properly account for differences in scale or the capacity density of DNSP networks and the Canberra as the *Bush Capital* which has significant impacts on AAD's vegetation management costs and unplanned outages. These factors disadvantage AAD compared to other DNSPs.

Additionally, it is AAD's view that both DNSP benchmarking analyses by the AER inappropriately contain dual function assets and associated opex costs that are to be regulated as transmission assets in the 2014-19 regulatory period. These dual function assets should therefore be excluded from DNSPs opex costs.

AAD's view is supported by a report by Huegin Consulting included in attachment A that shows that AAD compares very favourably for customer outcomes such as SAIDI, SAIFI, and average residential revenue per kWh of energy delivered. Huegin notes that these outcomes:

> *"seem incongruous with the results of the MTFP analysis"*[3]

and have analysed the sensitivity of the model to several factors and found that AAD MTFP results are influenced by:

- The inability of MTFP to account for economies of scale
- The bias in the model to the influence of 132kV assets; and
- ActewAGL's low levels of overheads capitalisation.[4]

AAD draws on these insights from Huegin at various points in this response.

Consequently, AAD remains of the view that the AER's benchmarking analysis has numerous limitations and that the results should not be relied upon to deterministically set (or form the basis of) expenditure allowances for the 2014-19 regulatory period.

The significant limitations of the AER's application of the MTFP technique are demonstrated by the way in which AAD might be impacted if it was required to move to the AER's efficient frontier. These examples were calculated by Huegin Consulting and were provided on page 3 of

[3] Huegin, ActewAGL Productivity Perfromance Analysis, 30 September 2014, p 5

[4] Huegin, ActewAGL Productivity Perfromance Analysis, 30 September 2014, p 5

AAD's response to the AER's draft annual benchmarking report (29 August 2014). They demonstrate that reaching the frontier is an impossible task. Specifically, AAD would need to increase its outputs (holding all inputs constant) as follows:

- Increase energy distributed from 2,904GWh to 514,866GWh
- Increase its customer numbers from 384,000 to 791,071
- Increase its circuit length from 5.088 to 94,961 (holding MVA-kms constant), or

Similarly, AAD would have to decrease its opex from $76.8 million to $2.4 million p.a (holding all outputs constant).

In the following two sections, AAD raises two concerns about the comparability of the AER's current benchmarking analysis.

- Businesses have different capitalisation practices
- Abnormal and non-recurring opex items in 2012/13

The AER must ensure that these key issues are being addressed and benchmarking results adjusted for before any meaningful comparisons can be drawn.

1.2 Different capitalisation practices

1.2.1 Differences in accounting and cost allocation policies and practices across DNSPs have a material impact on opex benchmarking

In its written question to AAD on 23 September 2014 the AER provided data for Citipower and Jemena.

	ActewAGL	Citipower	Jemena
Opex	66,325	49,711	65,118
Customers	169,074	314,396	312,817
Line length	3,967	3,025	4,275
Maximum demand	651	1,415	980
SAIDI (MED days removed)	33	28	60
SAIFI (MED days removed)	0.65	0.45	1.01

AAD is of the view that these figures indicate there are different accounting and cost allocation practices of each DNSP.

In addition, AAD notes that in the table above, the line length for AAD appears to exclude its underground services cables. In the ACT, when the residential building is set back from the block, the boundary cable running from a pit or pillar into the block is regarded as a service cable as is the cable that runs directly from the pit or pillar straight into the block. However, AAD understands that in Victoria, for underground arrangements, the pit is installed at the front of the property boundary and the service cable ends at the pit – the point of supply is at the pit. Any connections downstream from the pit are the customer's responsibility and ownership, i.e. customer's mains. As a result, a more comparable line length for AAD would be approximately 1,000 km higher that AAD is responsible to maintain than 3,967 km as referred to above.

The need to ensure data comparability when benchmarking DNSPs was identified as a key issue and responding to the AER's forecast expenditure assessment guideline in September 2013.

More recently, AAD noted in its response to the AER's draft annual benchmarking report that it:

> *…is highly unlikely that all DNSPs capture network data and categorise costs in the same way and therefore also unlikely that the AER's benchmarking analysis is based on a like for like comparison.*[5]

In its responses to the AER's draft category analysis benchmarking report, AAD also noted that:

> *…single output/single input benchmarking metrics are limited in what they can inform due to variations in reporting procedures, cost allocation and accounting methods across DNSPs. It is often the case that businesses will appear 'efficient' in certain category measures and 'inefficient' in others and this may be attributed to a different cost allocation method……this could also explain why ActewAGL Distribution's operating expenditure appears to be above its peers in some metrics*.[6]

In raising these concerns, AAD believes that there is an opportunity to engage further with the AER so that there is a greater understanding of AAD's costs and cost drivers, relative to other DNSPs.

Differences in accounting and cost allocation practices have been recognised by the AER in the past. In assessing AAD's costs for the 2009-14 regulatory period, the AER's engineering consultant noted that AAD's indirect costs seem to be high but qualified this by stating that:

> *This appeared to be due at least in part to a relatively low level of allocation of overhead to direct maintenance and capital costs compared to the other DNSPs, which means less overhead may be capitalised in comparison to the other DNSPs. Additionally, ActewAGL leases its motor vehicles and computer equipment and that contributes to a higher level of opex compared to the other DNSPs, all of which own their vehicles and equipment*[7].

AAD presents three key examples in relation to AAD's capitalisation practices and how these are likely to have impacted the AER's benchmarking results.

1. Revenue building block comparison and capitalisation of overheads

---

[5] ActewAGL *Response to the AER's Draft Annual Benchmarking Report,* August 2014 p.10

[6] ActewAGL, *Response to the AER's category analysis benchmarking report,* August 2014 p.4

[7] Wilson Cook & Co - ACT & NSW DNSP Expenditure Review – ActewAGL FINAL, October 2008, p 34

2. Leasing of vehicles and computers affect benchmarking

3. Changes to AADs CAM.

1.2.1.1 Revenue building block comparison

Evidence that AAD expensed more and capitalised less of its expenditure than other DNSPs is provided in an analysis of the composition of each DNSP's revenue building block. Table 1.1 below shows that AAD's return on capital is the lowest of all businesses, while AAD's operating expenditure is the highest.

Table 1.1 Composition of DNSPs revenue building block

	Return on capital, %	*Opex, %*	*Other, %*
NSW/ACT 2009-14			
ActewAGL	***38***	***46***	***16***
Country Energy (Essential)	***43***	***39***	***18***
Integral (Endevour)	***46***	***36***	***18***
Energy Australia (Ausgrid)	***55***	***34***	***11***
Simple average ACT/NSW	***46***	***39***	***16***
Victoria ***2010-2015***			
Citipower	***61***	***21***	***18***
Powercor	***49***	***34***	***17***
Jemena	***44***	***31***	***25***
SP Ausnet	***50***	***38***	***12***
United Energy	***46***	***35***	***19***
Simple average Victoria	***50***	***33***	***17***
South Australia *2010-2015*			
ETSA	***45***	***32***	***23***
*Queensland 2010-2015**			
Ergon	***66***	***30***	***4***
Energex	***71***	***25***	***4***
Simple average Queensland	***68***	***27***	***4***

**Queensland's revenue building blocks include significant negative adjustments.*

One reason for the variations in return on capital component of revenues could be the differences in the average age of network assets. However, attachment B from Hueing shows that in comparison to Citipower, AAD's age for five significant asset groups is lower.

If AAD's return on capital component of revenue were to be equivalent, for example, to the Victorian average (50%), AAD's opex during the 2009-14 would halve to be below $40m in nominal terms during the 2009-14 regulatory period. If AAD's return on capital were to be as high as, for example Citipower (61%), AAD's opex would decrease by 80%. Similarly, Huegin Consulting has analysed data in the Economic Benchmarking Regulatory Information Notice (EB RIN) and the results of this analysis (page 10 of attachment A) shows that AAD's overall split between capex and opex is the lowest amongst the DNSPs. For example, AAD's capex: opex split is 51 per cent, compared with 63 per cent for Jemena and 74 per cent for CitiPower.

In addition to the above (and consistent with Huegin's analysis on page 10 of attachment A), AAD notes that the category analysis data set used by the AER indicates that during the benchmarking period considered by the AER (2006 – 2013), AAD capitalised less than other DNSPs. For example during the 2009-2013 period, AAD capitalised $1.9 million/annum of its overhead and expensed $13.8 million/annum. In sharp contrast, Citipower capitalised $13.7 million/annum of its corporate overhead costs and expensed $7.5 million/annum. Table 1.2 below compares the average capitalised and expensed corporate overheads during the period 2009-2013, and indicates very different capitalisation policies between the businesses.

Table 1.2 Average capitalised and expensed overhead expenditure during 2009-2013, million

Business	Capitalised overhead	Expensed overhead	% capitalised overhead	% expensed overhead
ActewAGL	**1.9**	**13.8**	**12.4%**	**87.6%**
Ausgrid	29.9	97.9	23.4%	76.6%
Citipower	**13.7**	**7.6**	**64.3%**	**35.7%**
Endevour	21.7	56.9	27.6%	72.4%
Energex	140.5	98.3	58.8%	41.2%
Ergon Energy	118.4	63.7	65.0%	35.0%
Essential Energy	91.9	75.4	54.9%	45.1%
Jemena	**6.6**	**15.2**	**30.4%**	**69.6%**
Powercor	24.2	22.5	51.8%	48.2%
SA Power networks	1.4	48.7	2.8%	97.2%
SP Ausnet	10.1	5.1	66.6%	33.4%
Aurora	6.4	21.9	22.8%	77.2%
United Energy	0	42.7	0%	100%

Source: AER, DNSPs – opex and overheads, Expenditure summary (spreadsheet)

Table 2 demonstrates that AAD capitalised significantly less corporate overheads than most other DNSPs during the period 2009-2013. This analysis is also supported by Huegin (page 10 of attachment A). Using reported data in the EB RINs, Huegin's analysis shows that AAD has the lowest capitalised overheads in the EB RINs. For example, AAD's level of capitalisation of overheads is 6 per cent, compared with 34 per cent and 51 per cent for Jemena and CitiPower respectively.

AAD's network price comparisons contained in AEMC's *Electricity price trends* reports show that AAD has the lowest network prices in Australia.[8] In relation to the capitalisation practices, it is

[8] AEMC, Electricity price trends, Final Report, December 2013

worthwhile noting that AAD and Citipower appear to be sitting close to the opposite ends of the spectrum. AAD considers that the AER must normalise for the substantial differences between the capitalisation practices before any conclusions regarding businesses opex productivity can be drawn.

1.2.1.2 Leasing of vehicles and computers affect benchmarking

During the period under consideration by the AER for benchmarking, (2006-2013) AAD's practice was to employ operating lease arrangements for most vehicles. In 2012-13 AAD incurred approximately $2.5million in operating lease expenses for its vehicles. In comparison, finance lease arrangements were used by Victorian and NSW DNSPs which have the effect of adding these asset values to the asset base (and RAB), rather than the ongoing annual operating expenditure. Similarly, during the same period AAD had all of its computers on operating lease arrangements. AAD estimates that in 2012-13, its opex was approximately $0.4 million higher than most other DNSPs because of operating lease expenses in respect of leased computers.

Similarly, during the same period AAD had all of its computers on operating lease arrangements. AAD estimates that in 2012-13, its opex was approximately $0.4 million higher than most other DNSPs because of operating lease expenses in respect of leased computers.

As a result, AAD's total opex for 2012-13 is likely to be approximately $3 million higher in comparison to other DNSPs simply due to different accounting treatment of vehicles and computers.

1.2.1.3 Changes in the CAM

AAD is aware that it expensed more of its expenditure during the previous regulatory period than other DNSPs as its old CAM (that was used for regulatory purposes until 30 June 2014) expenses relatively more (about $10 million/annum). One important change to the new CAM is that all overhead expenditure from 1 July 2014 is allocated to all projects (capex and opex), whereas previously only 15% of overhead costs was capitalised.

Despite recent changes to AAD's CAM to bring it more in line with other DNSP practices, it is likely that there remain inconsistencies in relation to capitalisation policies and CAMs as well as individual interpretations how to apply these methodologies and that other DNSPs continue to capitalise more than AAD. The comparison of the revenue building block in Table 1.1, capitalisation of overhead costs in Table 1.2, and on page 10 of attachment A provides a strong indication that this is the case.

Based on the observations above, AAD urges the AER to look into this very important issue and normalise the benchmarking results.

1.3 Abnormal and non-recurring opex items in 2012/13

In addition to different capitalisation practices, AAD's opex in 2012/13 is likely to be overstated compared to other DNSPs due to several abnormal and non-recurring items. These include:

- Vegetation management costs of $1.9 million
- Comcare exit fees of $1.8 million
- Energy Industry levy $0.7
- Under recovery of capex $2.9

Vegetation management

To ensure that operating expenditure does not include abnormal and non-recurring items it is necessary to remove ActewAGL Distribution's vegetation management costs included in the deemed approved pass through of $1.9 million.

ActewAGL Distribution experienced a material increase in vegetation management costs in 2012/13 due to the uncontrollable and unexpected increase in vegetation growth following two years of above average rainfall. Rainfall in 2010/11 and 2011/12 was the highest since 1988/89, over 20 years prior.

As the expenditure was a result of an abnormal non-recurring event the expenditure itself is abnormal and non-recurring. This is reflected by ActewAGL Distribution's forecast operating expenditure for the vegetation management program and ActewAGL Distribution's expenditure in years preceding 2012/13.

Comcare exit fees

As noted in AAD's regulatory proposal (page 225), in 2012/13 AAD also incurred a Comcare exit fee for ACTEW Corporation's decision to exit the ACT Government's Comcare arrangements under the Safety, Rehabilitation and Compensation Act 1988 (Commonwealth) (the "Comcare Scheme"), effective 1 September 2012. Given that this was a clear non-recurring item, AAD excluded this cost from its base year that was used for its 2014-19 opex forecast. Likewise, this cost should be excluded for benchmarking purposes.

Energy Industry Levy

During the 2009-14 period, AAD paid an Energy Industry Levy to recover the amount of the ACT's national regulatory costs and local regulations costs. Given that this is a cost that from 2014 will be classified as a jurisdictional scheme, it should be excluded when AAD is benchmarked against other DNSPs.

The Energy Industry Levy in 2012/13 was $0.7 million and varies year by year.

Under recovery of capex

Cost recovery is a mechanism of allocating resources employed by AAD as they are utilised to deliver capital, maintenance and operational projects. The collection of resources, which is viewed as a cost pool, consists of various elements: direct labour, overhead labour, and plant and equipment. Key drivers of cost recovery variations to the cost pool are labour utilisation percentage, timesheet entry and the amount of leave taken by staff members. In 2012/13, AAD under-recovered its cost pool in relation to timesheet entry, labour utilisation percentage and leave taken by staff members partly due to implementing the new business structure after the Marchment Hill recommendations, which resulted in approximately $2.9 million not being allocated to capital so expenditure remaining as unrecovered operating expenditure.

1.4 Summary of opex adjustments to 2012/13

AAD considers that the AER must ensure that variations in capitalisation policies across DNPS, and abnormal and non-recurring opex for AAD in 2012/13 are captured and adjusted by the AER's in its benchmarking techniques. These adjustments that amount to about $20 million are summarised in Table 1.3 below. In addition, the AER also needs to normalise the treatment of 132 kV assets (see Section 3.4 below).

Table 1.3 Summary of changes to benchmarking

Item	Description	Financial effect
Capitalisation practices	Benchmarking of DNSPs revenue building blocks strongly indicates that there are significant difference between how DNSPs capitalise their expenditures.	AAD believes that it has capitalised at least $10m/annum less than other DNSPs.
Leasing of vehicles and computers	Unlike DNSPs in NSW and Victoria, AAD's vehicles are leased on an operational basis (rather than finance lease)	~$3m in 2012/13
Vegetation management	AAD experienced a material increase in vegetation management costs in 2012/13 following two years of above average rainfall.	$1.9m in 2012/13
Comcare exit fees	Exit fee for the decision of ACTEW Corporation to exit the ACT Government's Comcare arrangements.	$1.8m in 2012/13
Energy industry levy	An ACT specific fee to cover the costs of regulation in the ACT.	$0.7m in 2012/13
Under-recovery of capex	In 2012/13, AAD under recovered its cost pool resulting in higher allocation to opex.	$2.9m in 2012/13
Total		**~$20 million**

2 Capital expenditure

In this section, AAD provides a brief background to the drivers of capital investment and planning requirements. AAD then provides a summary of its effective governance and risk management framework for capital investments. This is followed by a summary of AAD's processes for managing capex/opex trade-offs as well as ensuring prudency and efficiency. Finally, AAD responds to remarks made by the AER at the meeting on 16 September 2014 that AAD should focus capacity provision based on outputs rather than input measures.

The response to AER's questions (covered in Part 2 of this response) demonstrate in greater detail that AAD has governance frameworks and planning processes in place to manage capital investment prudently and efficiently, considering where possible capex/opex trade-offs, risk consideration and customer focussed approaches.

Background

AAD's capital investments are developed in response to identified needs in the network, such as:

- to meet customer demand;
- reliability and security;
- investing in non-network solutions; and
- investing where economies of scale provide economic benefit.

Distribution network augmentations generally grow in step changes. The challenge in delivering long-lead infrastructure to match demand is to have planning strategies in place and refine project augmentations as the need for the augmentation is established with a high level of certainty. Therefore, prudent planning requires making long term (10 year) decisions on the growth potential of zone substations which ensures that the scale of improvement carried out is efficient and prudent.

The AAD network is not highly meshed. This is due to the planned nature of the ACT urban environment with residential & commercial areas separated by nature vegetation corridors and parklands. Therefore there are less interdependencies between projects; that is, investment in one part of the network tends to be "localised" and may not be able to meet the demand created by a new development in another part of the network. Core grid reliability improvement projects are highly limited in AAD's system. Most of the CAPEX is related to replacement CAPEX and customer initiated and augmentation projects to meet load at new developments, where alternative supply points are often not established.

AAD has an effective governance framework for capital investment

To ensure that capital investment has an effective governance framework, AAD has implemented corporate policies, delegations manual, and approvals processes.

There are two approaches adopted by AAD to manage capital investment. The first approach focuses on managing investment that is 'business as usual' and the second is to use 'Project Boards', the latter generally to deliver major CAPEX projects or one-off non network CAPEX. In recent times, the use of Project Boards as a project decision making and delivery governance has been successfully implemented in capital investment for the Operational Systems Replacement Program (OSRP) program, which is in its final stages of implementation.

Formalised Framework for Risk management

AAD's CAPEX activities are supported by the formalised risk management framework and legal compliance framework. These frameworks are:

- Risk Management Framework (RMF) consistent with AS/NZS ISO 31000:2009
- Legal Compliance Framework (LCF) that conforms with AS 3806:2006

AAD has a number of complementary and rigorous processes to ensure that legal and regulatory obligations are complied with, risks understood and communicated and that the prudency and efficiency of planned projects is assessed and achieved.

For example, AAD invested in purchasing and maintaining the CMO software, which is a comprehensive database of obligations. Implementation of the CMO has improved end to end capability, ensuring the capture and implementation of new and amended obligations relevant to ActewAGL's operations, and monitoring of compliance against these obligations. For example, the implementation of NECF included training and support activity for both CMO and for NECF compliance in general. This included training right across the business on how to use CMO, and also includes fact sheets, intranet content and other services (for example, legal advice) to optimise compliance with the NECF.

New or changed obligations are captured using updates from an external legal service provider who provide a quarterly assessment of the relevant legislation via the CMO Compliance Software. The communication plan from the CMO systems and the follow up from the Legal & compliance group is thorough. There is a comprehensive legal compliance process which explains the process of capturing legislative changes, assess the impact on the business, communicate changes within the organisation and specifically to responsible business owners and determine the course of action.

AAD notes that the recent change to the Electricity Distribution (Supply Standards) Code 2013 (and simultaneous revoking of the ACT Electricity Distribution (Supply Standards) Code 2000 and confirms that this has had no material impact on AAD's CAPEX proposal for the next regulatory period.

AAD's approach to Capex Optimisation and Capex/Opex Trade-offs

CAPEX-OPEX trade-offs are inherent in a number of decisions being made by AAD. The required trade-off analysis is, for example, usually undertaken in the case of refurbishment and replacement of ageing and potentially unreliable equipment, where the ongoing maintenance, repair, and fault costs (including loss of supply) can be compared with the capital cost of refurbishment and replacement.

An example of a decision based on CAPEX-OPEX trade-off evaluation is the move to fibreglass poles in 'back yard' installations to reduce life cycle costs of maintenance of those assets. The majority of genuine CAPEX / OPEX trade-off evaluations are not assessed on a project by project basis, but on an asset class basis, and AAD has several examples of these referenced in its regulatory proposal.

AAD uses a risk based decision support model "Analysed Program of Works" to optimise its 5 year CAPEX replacement program and to make decisions on capex/opex trade-offs. In particular, AAD's model considers the failure effect and risk (likelihood and consequence) of each investment decision. Based on the determined failure effect for each asset under consideration, one of the following replacement strategies is adopted and an optimal time for replacement or monitoring is identified:

- Run to failure;
- Condition monitoring; and
- Age and condition based replacement.

The Analysed Program of Works model was implemented to prioritise AAD's replacement CAPEX and establish non-discretionary and discretionary replacement CAPEX budgets.

Jacobs (formerly SKM) and AAD applied energy-at-risk modelling in AAD's 2009-14 regulatory reset to demonstrate the economic justification for the replacement of the 11 kV switchboards at the Civic zone substation.

However, the relatively small size of the AAD system and the infrequency with which major substations or feeders become overloaded does not present many opportunities to apply energy-at-risk modelling. In relation to the 2014-19 regulatory period, there are a small number of potential opportunities to apply energy-at-risk modelling. In future, AAD will consider applying energy-at-risk modelling to suitable projects to optimise the timing and capital expenditure. In most cases the time it takes to transfer load to neighbouring substations has been calculated in relation to maintaining reliability on the core grid and customer supply.

Prudency and efficiency of capital investments

Prudency in the context of planning for uncertainty requires AAD to undertake planning initiatives with load development triggers (forecast demand) identified to meet conditions where the rate of load growth is not known. The capital works planning undertaken as a key input into the regulatory proposal deals effectively with expenditure that is required to be undertaken during a regulatory period, but which is not able to be predicted with certainty at the start of the period.

Timing of investment can be established with more certainty closer (18-24months) to the implementation of the projects. In such cases, it is not prudent for AAD to hold off planning until a high degree of certainty can be established. AAD develops long to medium term capital works plans (5 – 10 year) based on reasonable demand forecast triggers. It would be imprudent for AAD to not take these large anticipated load growth projections into consideration in its planning activities.

There are three projects that are elaborated here to illustrate AAD's approach:

- Belconnen 3rd Transformer: AAD's recommendation is that a capital budget allowance be made in the next regulatory period for a third transformer at Belconnen ZS is required to meet expected demand.
- Molonglo Zone Substation: The Molonglo project solution will be finalised via the RIT-D process outcome.. The timing for this project has been based on forecast demand requirements. The RIT-D process will be triggered through the annual planning process where the timing for the project will be reassessed based on a defined load trigger (demand).
- Gold Creek Switchboard augmentation: Key drivers supporting the demand forecast include continued baseline growth in existing residential areas, continued developments in areas such as Casey and Crace, new development areas such as Moncrieff, Taylor and Throsby, and known customer initiated spot loads in the Mitchell area which includes the [redacted] The project justification report (PJR) for Gold Creek has considered a range of options for consolidation of 11kV feeders, but the underlying healthy demand forecast plus the prospect of at least 2 major spot loads is compelling. Planning for a zone substation to supply a 6% p.a. demand forecast, 50MVA of existing load, possible spot load increases, and twenty (20) existing 11kV feeders with no spare 11kV circuit breakers, and no plan to install any additional breakers will not meet expected demand. It is common and a minimum prudent practice to have 1 or 2 spare 11kV circuit breakers on each 11kv zone switchboard in urban areas to cater for generic growth, unexpected spot loads, and the occasional circuit breaker failure.

Where prudency had identified a project and the scope definition is not clear, AAD uses good engineering practices and network operational experience to develop a better understanding of the scope through a project life cycle. A typical method of seeking sufficient definition to enable planning is to undertake sufficient minimal works to clarify the scope (and risk).

An example of this is where AAD is proposing to carry out condition monitoring of earth grids at its 15 zones substations, as most of the earth grid at zone substations are in excess of 30 years of age and now pose a safety risk. The physical condition of the earth grids, particularly those of the greatest age, is largely unknown. In the absence of condition assessments of the earth grids at the time of submitting capital budget estimates, the age of the asset was used to estimate four different levels of refurbishment that may be required to be undertaken. This is a prudent method to estimate expenditure, as it is not likely to understate expenditure (given the age of assets) nor overstate it, until the outcome of the condition monitoring assessment is available.

Separately, AAD noted that the AER mentioned a $7 million capital budget for earthing grids. AAD believes this is an erroneous comment and AAD can confirm a capital budget of $2.6 million for all zone substations being assessed in the 2014-19 regulatory period. As the condition assessment of each earth grids is carried out, the budget will be revised to reflect actual expected costs.

AER's general comment that capacity provision should be outputs rather than input focused

The AER made a general comment at the 16 September meeting, which AAD has interpreted as:

> *AAD's focus should be on output (customer service), not input focused capacity provision criteria. AER expects capex to decrease markedly if AAD were to take this approach, based on $4bn reduction in NSW*

The following discussion provides the AER with substantive baseline distribution planning practices and to assist the AER's understanding and appreciation of the complexities involved and respectfully recommend caution with simplistic statements of this nature, where they underpin the AER's thoughts of the SRP review and approvals processes.

The distribution code specifies a range of technical parameters, such as frequency, steady state voltage limits, voltage dips and fluctuations, voltage unbalance, harmonics, lightning protection, levels of EMF's, quality of supply, etc. These are all technical parameters which are normally specified in state based legislation or regulations.

There is no uniform Australian standard or regulation covering these technical parameters of the distribution system in each state. The previous distribution code also specified some minimum SAIDI and SAIFI reliability targets (Section 7 and Schedule 2). The SAIDI and SAIFI targets set were based on the levels achieved by AAD in 1996/97, and do not reflect any improvement over time. This "flat target approach" is inconsistent with past AER practice of setting steadily improving reliability targets for each 5 year regulatory period.

AAD has not included any additional capex provisions in the SRP specifically designed to improve overall system reliability. Such reliability improvement strategies would normally include installation of reclosers and sectionalisers, extensive undergrounding of overhead, use of covered conductor or aerial bundled conductor (ABC), or a significant investment in "smart networks". AAD has not planned to undertake any significant reliability improvement projects. Therefore, should the AER decide to set "improving trend targets" for the 2014/19 regulatory period, it will be necessary to recognise any additional costs that will be required to comply with these new reliability targets.

Another key point to note is that the ACT Distribution Code (2000) did not include any requirements that either directly or indirectly specified the "security of supply" (i.e. N-1, or other) that should be built into AAD's distribution and transmission systems. The decision as to what level of system security should be built into the distribution and transmission systems is the DNSP's responsibility in most states (except NSW, where it was dictated by state issued guidelines that came into force in 2007). These state issued guidelines specified N-2 security to the CBD of Sydney, and N-1 for all zone substations above about 10-15MVA (over the following regulatory period). This situation in the ACT therefore differs significantly from the NSW for both the 2008/09 reset and the current reset.

In Queensland after the Somerville inquiry of 2003/04, the State Government required Ergon Energy and ENERGEX to meet N-1 security at all zone substations above 5MVA, although this requirement was mitigated by the DNSP's establishing several different definitions of N-1 (e.g. N-1(a) – no loss of supply for single contingency, N-1(b) and (c) involving some loss of supply with restoration after a specified time period, etc.).

Nevertheless, AAD has not implemented security of supply standards that followed the NSW and Queensland examples, and does not have the diverse mix of urban and rural systems that require the application of different security of supply standards evident in NSW and Queensland. To demonstrate this difference, it should be noted that AAD has a 13 zone substations (132/11kV and 66/11kV) with existing and forecast loads of between 16MVA and 100MVA over the next regulatory period. Where prudent and feasible, AAD has implemented an N-1 security of supply arrangement by the interconnection of Zone Substations (via the 11kV feeder network). AAD has achieved this at the recently installed East Lake Zone Substation that has one (1) 132/11kV transformer installed. N-1 support is achieved via 11kV interconnections to Telopea Park and Fyshwick Zone Substations.

The only zone substation with a maximum demand of less than 15MVA is the proposed Molonglo zone substation, with a forecast demand up to about 10MVA by 2023. AAD proposes to initially install only a single power transformer at Molonglo, and to back that transformer up on the 11kV distribution system (i.e. N-1, with loss of supply until restoration by manual switching). This is consistent with the level of security of supply practiced by other DNSP's. The observation from the AER that the "*… focus should be on output (customer service),* [and] *not input focused capacity provision criteria*" is considered to be simplistic and incorrect. There are two dimensions to the proper design of distribution power systems:

1. **System Security** (capacity criteria) is the design of the power system to meet the maximum demand required by the customers, both under normal system conditions, and under credible contingency conditions (that is, the customer does not expect to lose supply in instances where the electricity distribution utility has a transformer out of service for maintenance). Often the investment in system security is required to protect against HILP (high impact, low probability) events, such as the catastrophic failure of a major bulk supply substation or zone substation. While it is such a rare event, and is not reflected in average annual system reliability statistics, the magnitude and wide-spread

nature of the resultant supply outages of any occurrence can cause significant community and business disruption. Examples of recent HILP events include the Auckland CBD cable failures in February 1998[9], the Melbourne CBD loss of supply in January 2001[10] and the severe storm season in Queensland in 2004 that resulted in the Somerville Inquiry.[11] There have also been severe loss-of-supply events in Sydney including complete loss of zone substations, and multiple 11kV feeder cable faults in the CBD. Often after such events there has been political intervention, public inquiries, and directions to DNSP's to improve security of supply. Generally speaking, investments in additional system security will have little impact on system reliability (SAIDI & SAIFI), since these are short term measures (typically 5 year averages) which exclude extreme events such as the HILP events that investment in system security is designed to protect against.

2. **System Reliability** (customer service criteria) is the design of the power system such that it meets the customer's reasonable expectations of reliability. No power system is 100% reliable, but should deliver a level of reliability commensurate with the customer's reasonable expectations, and preparedness to pay. AAD's level of system reliability is already at "best practice" levels compared to Australian peers. This is in part due to the relatively high level of undergrounding (55%), and the reasonably compact supply area and moderately good customer density. AAD has previously looked at the conventional methods of reliability improvement (e.g reclosers, sectionalisers, etc) and has found that there are only a limited number of situations on the distribution system where significant reliability improvement could be achieved in a cost effective way. As such, AAD has not committed to spend any significant amount of CAPEX on prime-purpose reliability improvement programs.

---

9 In January and February 1998 a series of cable faults occurred in the transmission network of the Auckland CBD. Through a combination of factors and circumstances during a 4-week period, a series of faults on the two 110 kV gas cables and two 110 kV oil cables resulted in the eventual loss of all supply to the Auckland CBD. Through the temporary installation of generators, and network augmentation and repairs, businesses were allowed to return to the Auckland CBD on 27 March 1998.

10 In 2001, two major incidents resulted in supply interruptions to the CBD. These events provided the trigger for CitiPower's review of security standards for the CBD. In January, approximately 12,200 customers were off supply for an average of 30 minutes. A further 100,000 people in the CBD area were directly affected by this incident. In November, over 65,000 customers were off supply for up to 64 minutes. It is estimated that a further 100,000 to 200,000 people within and surrounding the CBD were directly affected by this incident. Both incidents highlighted a lack of transfer capacity on the 66kV network.

11 A series of 5 severe thunderstorms in ENERGEX's area in the last week of January 2004 resulted in large numbers of customers being without power for extended periods. These January storms were followed by two days of very high winds (up to130km/hour) and heavy rain on 5 and 6 March 2004. As a result, the Queensland Government commissioned an enquiry chaired by Darryl Somerville to examine the then current state of Queensland's electricity distribution networks and their capacity to meet future needs.

PART 2

3 Specific operating expenditure questions raised by the AER

3.1 Backyard reticulation

AER Question

Raised on p.243 of ActewAGL regulatory proposal

We consider that backyard reticulation is not likely to lead to material differences in costs between ActewAGL and other service providers.

ActewAGL has reported a total network length of 5,088km. The proportion of backyard reticulation of this network is described in table below.

Network component (circuit length)	*(km)*	*Proportion (%)*
ActewAGL Total network	*5,088*	*100%*
ActewAGL overhead network	*2,394*	*47%*
ActewAGL low-voltage overhead network	*1,184*	*23%*
ActewAGL backyard reticulation network	*755*	*15%*

We agree with ActewAGL that backyard reticulation will have impacts on the costs associated with vegetation management, maintenance, and replacement on a per unit basis. However, we note that:

1. *the backyard reticulation network is a small proportion of ActewAGL's overall network total overhead line maintenance represents approximately 15% of total operating and maintenance expenditure. Backyard reticulation lines represent approximately one quarter of total overhead lines and are solely low-voltage lines.*
2. *ActewAGL's network is mostly underground, which should lead to lower opex costs than other networks (as there are lower ongoing maintenance costs for underground assets)*
3. *ActewAGL is only responsible for trimming 1.3% to 1.4%of the length of its lines. In other words, the customer is responsible for trimming the vast majority of backyard reticulation lines and therefore incurs the costs for this activity, not ActewAGL.*

AAD's RESPONSE

AAD incurs additional pole inspection costs for all poles located in backyards for the following reasons:

- Before inspecting (pole inspections and vegetation mgmt. inspections), AAD must notify the owner via letter that it requires access to the property.
- In 23% of the cases of pole inspections the gates are locked, or there are animals in the gardens, that prevent the crew from undertaking the inspection requiring a revisit.
- Pole inspections take more time as the crew must gain access to backyards. AAD conservatively estimates that that every pole inspection adds 10 minutes due to the location of the poles in the backyards.
- Vegetation management inspections take longer time as the crew must enter the properties.
- Cost of maintenance cost for poles and lines are higher in the backyards due to issues with accessibility. The normal mobile elevated work platform cannot access the backyard poles and overhead asset for maintenance. Scaffolding will need to be erected to provide electrical worker a platform to safely work on these overhead assets. Additional cost and time is required to setup the scaffolding before the maintenance work commences.

The difficulty and extra work associated with gaining access to backyard poles for inspection, maintenance and vegetation management contribute to AAD's operating expenditure in the following way:

1. AAD incurs additional costs for sending out notification letters to property owners for vegetation management and pole inspections. In relation to vegetation management, AAD also sends out a second letter with a picture of the encroachment that explains what the property owners must do. AAD estimates that the administration costs for these notification letters is $0.14 million and would not be incurred by AAD were the poles positioned in front of the buildings.
2. In 2012-13, the number of poles inspection that were cancelled due to access issues were 100 out of a total of 3,715. [redacted]. Number of vegetation management inspections that were cancelled was 880 (estimated to be 2% of all 1st inspection). There were 44,093 of 1st inspections in 2013/14. The estimated cost for cancelled vegetation management inspections is[redacted] = $0.07 million.
3. Pole inspections: the total cost for pole inspections is approximately $4.6m per annum. AAD inspects approximately 15,000 poles for an average cost of [redacted]/pole (including overhead costs). The additional time it takes to inspect a pole in the backyard is about 10 minutes. 15,000 inspections x [redacted] additional cost for inspecting poles in the backyards (excluding administration for notifying property owners).
4. Vegetation management inspections: the total cost for these inspections is approximately $1.4m per annum. AAD undertakes approximately 44,000 inspections

yearly resulting in an average cost per inspection of approximately [redacted]. A significant driver for this cost is the cost of accessing the backyards as the crew otherwise could undertake the inspections in a more automated manner from their own vehicles. AAD estimates the additional costs for inspecting the backyard reticulations to be approximately 50% of the total cost, making the additional cost $0.77 million per year.

[redacted]AAD incurs additional planned opex and reactive maintenance opex for poles and lines due to access issues into the backyards. For its planned maintenance, on average over the last five years there have been 165 occasions per annum where access issues has required additional scaffolding and 357 occasions per annum for reactive maintenance. The additional costs for these access issues (primarily scaffolding) is estimated to be [redacted]

In contrast to the AER's conclusion that the customer is responsible for trimming the vast majority of backyard reticulation lines and they incur the costs for this activity rather than AAD, the explanation above clearly shows that the additional opex impact of backyard poles and reticulation is approximately $2 million for AAD (sum of points 1-5 above).

3.2 Economies of scale

AER Question

ActewAGL is one of the smallest networks in the NEM and hence may be disadvantaged in benchmarking comparisons by diseconomies of scale. However, we consider that ActewAGL should gain economies of scale through its shared service functions across electricity, gas, and retail. Further, ActewAGL can gain economies of scale by outsourcing its works to other, larger organisations (such as Zinfra).

Additionally, ActewAGL spends more on opex than other networks despite having lower outputs. Direct comparison of ActewAGL to Citipower and Jemena illustrates this.

ActewAGL/Citipower comparison

	ActewAGL	*Citipower*
Opex	*66,325*	*49,711*
Customers	*169,074*	*314,396*
Line length	*3,967*[12]	*3,025*

[12] As noted in section 1.2.1, the line length in this table for AAD appears to exclude its service cables, which AAD has the responsibility to maintain but which customers have to pay for in Victoria. As a result, a more comparable line length for AAD would be approximately 4,930 km that AAD is responsible to maintain than 3,967 km as referred to above.

Maximum demand	*651*	*1,415*
SAIDI (MED days removed)	*33*	*28*
SAIFI (MED days removed)	*0.65*	*0.45*

Data source: EB RIN

This comparison reveals that ActewAGL spends 33 per cent more on opex than Citipower despite having lower outputs. Both ActewAGL have very reliable networks. We note that the SAIDI and SAIFI exclude the effect of MED days. When MED days are included ActewAGL performs better on SAIDI however still performs worse on SAIFI.

ActewAGL/Jemena comparison

	ActewAGL	*Jemena*
Opex	*66,325*	*65,118*
Customers	*169,074*	*312,817*
Line length	*3,967*	*4,275*
Maximum demand	*651*	*980*
SAIDI (MED days removed)	*33*	*60*
SAIFI (MED days removed)	*0.65*	*1.01*

Data source: EB RIN

ActewAGL spends a comparable amount of opex to Jemena. However, ActewAGL serves half the number of customers, has a lower maximum demand, and a shorter line length. ActewAGL out performs Jemena on the reliability indicators however both businesses have reliable networks.

AAD's RESPONSE

AAD does achieve some economies of scope through its shared service functions across electricity, gas, and retail businesses. AAD notes that it is able to outsource parts of its work to other organisations when AAD does not have the capacity or appropriate skills to undertake the work itself. AAD's work undertaken itself is cost efficient.

Despite this, there are functions and features that disadvantage a small network (e.g. network control, economic and technical regulation, call centre functions, depot facilities). To address this, AAD engaged Huegin to review economies of scale and how this is considered in the AER's draft benchmarking modelling. Huegin's analysis is included as Attachment A and notes that economies of scale do advantage large businesses but is not captured in the AER's MTFP approach:

> *MTFP aggregates outputs into a single output index and inputs into a single input index. If the outputs and inputs are correctly defined and measured then this ratio of outputs/inputs provides an indication of the relative levels of productivity between DNSPs.*

Using MTFP to benchmark businesses operating in an industry with economies of scale will favour larger businesses (in terms of whatever outputs are used) at the expense of smaller businesses. This is because outputs (and therefore the output index) do not increase proportionately with inputs so the ratio between outputs and inputs is going to yield larger results as a business' outputs increase.

Given that economies of scale are not accounted for when using MTFP, caution should be taken when using this technique to ensure that the results reflect efficiency and not just varying levels of productivity available to different scale DNSPs.[13]

Using the data released by the AER, Huegin has constructed an industry opex cost function from which the change in opex given a change in output can be measured (customers and system capacity as outlined in the AER's Expenditure Forecast Assessment Guidelines have been used as outputs). Huegin states that:

Using the data released by the AER, Huegin has constructed an industry opex cost function from which the change in opex given a change in output can be measured (customers and system capacity as outlined in the AER's Expenditure Forecast Assessment Guidelines have been used as outputs). Huegin states that:

The respective output coefficients using this model were 0.37 and 0.16 (for customer and system capacity respectively). That is, the cost elasticities for customer numbers and system capacity are 0.37 and 0.16. Aggregating these two outputs into a single index allows the relationship between changes in the output and resulting increases in opex to be calculated. This analysis suggests that as output increases by 1%, opex increases by 0.31%, suggesting that returns to scale are present in the econometric modelling results, which in turn suggests it should be recognised in the MTFP results (which cannot account for returns to scale in the same manner as DEA and econometric modelling).

Of course, these results will change with changes in the functional form and variables used in the econometric modelling, however Huegin analysed several options from the set defined by the guidance in the AER's Expenditure Forecast Assessment Guideline and found returns to scale was a consistent presence in the results.[14]

Huegin also cited other reports which support the existence of economies of scale:

- Frontier Economics Report for OFGEM found cost elasticities of 0.469 for customers and 0.351 for peak demand - indicating that as output increases by 1% total costs increase by 48% ((Total cost benchmarking at RIIo-ED1 – Phase 2 report – Volume 1
- Pacific Economics Research Group for the Ontario Energy Board found cost elasticities of 0.408 for customer numbers, 0.071 for KWh distributed and 0.194 for peak demand indicating that an increase in outputs of 1% results in a total cost

[13] Huegin, ActewAGL Productivity Performance Analysis, 30 September 2014, p 7

[14] Huegin, ActewAGL Productivity Performance Analysis, 30 September 2014, p 7-8

increase of 0.31%(Productivity and Benchmarking Research in Support of Incentive Rate Settings in Ontario)

- Centre for Energy Policy and Economics Swiss Federal Institutes of Technology (Regulation and Measuring Cost Efficiency with Panel Data Models: Application to Electricity Distribution Utilities) found the following results using data from 59 Swiss distributors
  - Pooled OLS Model – 0.851 and 0.084 (GWh and Customer numbers respectively)
  - Random Effects Model – 0.78 and .153 (GWh and Customer numbers respectively)
  - Fixed Effects Model – 0.677 and .251 (GWh and Customer numbers respectively)

These reports all confirm that the electricity distribution industry is subject to significant returns to scale that will impact the results of MTFP benchmarking and significantly disadvantage AAD.

AAD refers to the report from Huegin in Attachment A to this response.

3.3 Hardwood poles

AER question

We consider that the replacement of hardwood poles will not affect opex.

AAD Response

AAD estimates that the additional opex impact of having hardwood timber poles in its network is approximately $1 million per annum.

Timber poles require inspection at and below ground level every 4.5 years. This involves excavating the soil from around the pole base, inspecting the integrity of the timber for rot, termite activity and the effects of moisture on the poles.

Whilst steel poles also require below ground inspections every 4.5 years, they are not susceptible to termite attack or timber rot. Additionally the steel poles have an outer galvanised coating providing protection against corrosion. Fibreglass and concrete poles do not require below surface pole inspections as neither are susceptible to rot, termite infestation nor rust.

AAD presented whole of life cost comparison (see Table 3.1 below) for timber and concrete poles in its SRP, in the context of AAD's ongoing pole replacement program. It noted that the annual operating expenditure requirement for below ground inspections was eliminated, realising operating expenditure savings that compound annually, as the timber pole population is progressively replaced with fibreglass and concrete poles. This operating cost saving was an input to the economic justification for the pole replacement program.

Table 3.1 Whole of life cost for timber and concrete poles

	Timber poles	*Concrete poles*
Asset life	Reinforce at 45 years; replace at 55 years.	80 years
Installation cost	$10,500	$12,660
Inspection cost	$348	$150
Inspection frequency	4.5 years	4.5 years
Assumed annual inflation rate	3%	3%
Whole of asset life at 45 years	$25,127	$14,505
Whole of asset life at 55 years (not including the cost of pole replacement	$28,049	$14,992

This whole of life costing analysis was undertaken by Jacobs SKM (Jacobs). Jacobs estimate the annual inspection cost of timber poles to be $348/pole, or more than double that for concrete poles ($150). AAD estimates that the additional opex impact of having hardwood timber poles in its network is approximately $1 million per annum.

As well as continuing the wooden pole replacement program during 2014–19 regulatory period, AAD will continue its extensive pole nailing (reinforcement) regime, to extend the life of condemned timber poles. Approximately 38 per cent of all timber poles in service are now reinforced and this ratio is forecast to increase slightly during the next regulatory period. AAD plans to reinforce approximately 700 wooden poles per annum over the course of the 2014–19 regulatory period.

3.4 Dual function assets

AER question

We consider that the difference in the amount of HV assets that networks must provide is a legitimate operating environment factor that affects costs. We consider that this will materially disadvantage the NSW and Queensland networks that have a significantly higher proportion of assets at and 33 KV. However, we consider that ActewAGL may have a cost advantage to other networks because it runs less of these assets. The proportion of total line length above 33kV for all the networks is presented in the figure below.

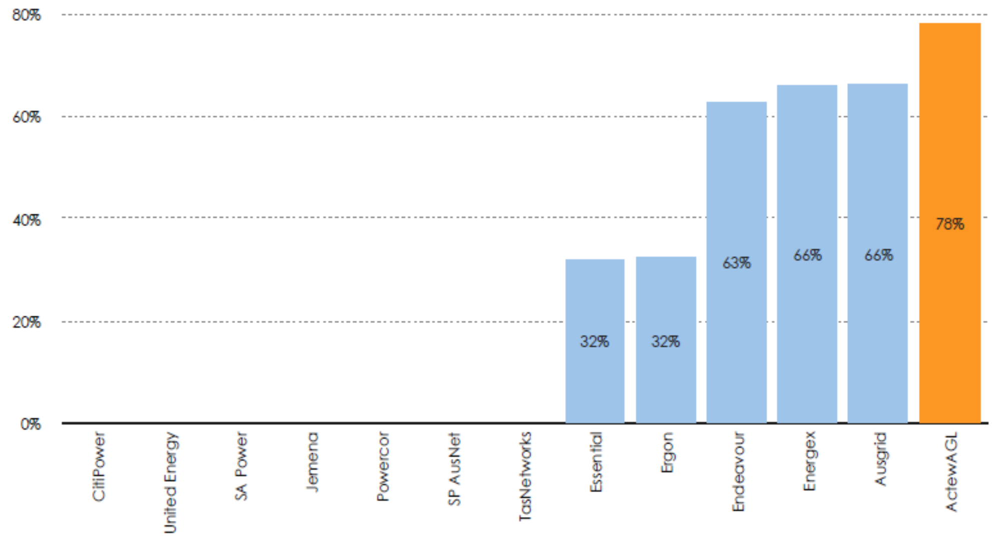
In its submission on the benchmarking report ActewAGL notes that the AER's MTFP analysis fails to take into account the high proportion of 132 kV assets. [p.3] Further, ActewAGL argues that the MVA-kms capital input measure in the analysis puts it at a disadvantage. We note ActewAGL's concerns. However, we have also conducted opex MPFP analysis of the distributors (which does not include capital inputs). Under this analysis ActewAGL does not perform well. As such, the high voltage assets in ActewAGL's network do not appear to affect its benchmarking performance.

AAD Response

AAD does not agree with the AER's conclusion for several reasons.

AAD's first concern relates to 132kV asset capacity, and not the length of line of 33kV and above assets. To illustrate this point, Figure 3.1 developed by Huegin shows that the contribution of 132kV (or 110kV) assets to the overall capacity input measure (OH and UG MVA-kms) is most significant for AAD.[15] By focusing on length, the AER has not addressed AAD's concern.

Figure 3.1 Contribution of 110kV and 132kV assets to input capacity (MVA-kms)



Based on this analysis, Huegin states that:

> *The fact that 132kV assets (OH and UG) contribute 78% to the input measure of capacity and just 3.8% to the output of circuit length (which is an output measure) is the most significant factor in ActewAGL's MTFP results. It is also worth noting that the six businesses with assets of 110 or 132kV voltage levels are those that benchmark poorly on the MTFP analysis.*[16]

Additionally, AAD advises that the result of the opex MPFP carried out by the AER is affected by the high level of overheads in AAD's opex—compared to other DNPs that capitalise significantly more of these overheads. It is not lower efficiency. If the AER were to use the same method to

[15] Huegin, ActewAGL Productivity Performance Analysis, 30 September 2014, p 9

[16] Huegin, ActewAGL Productivity Performance Analysis, 30 September 2014, p 9

measure opex MPFP as it has done to measure capex MPFP, by removing 132kV assets, AAD's opex MPFP performance would be significantly better than that measured by the AER.

Furthermore, in its response to the AER's draft category analysis benchmarking report, AAD proposed that the AER considers the use of capacity density as an alternative to customer density as a normalisation variable that should be considered by the AER. AAD suggested that this may be a more relevant explanatory variable of expenditure, particularly maintenance expenditure as networks with higher voltages are likely to incur higher maintenance costs (eg. more skilled labour, more stringent safety requirements). Huegin Consulting undertook partial productivity analysis of AAD's maintenance costs and total opex using capacity density as an explanatory variable.

These results indicate that AAD does not have any immediate peers from which to infer comparative efficiency and therefore demonstrate the pitfalls of benchmarking.

Moreover, AAD draws the AER's attention to the Huegin's analysis (Attachment A) which articulates the methodological weakness and bias introduced by the AER's inclusion of 132 kV assets:

> *…one of the amendments made to the MTFP model specification is the removal of system capacity as an output in the draft annual benchmarking report. The reasoning (provided by Economic Insights) was that the multiplicative measure of system capacity (capacity measured in MVA multiplied by line length) biases the results in favour of some DNSPs at the expense of others. A similar bias remains in the model through the use of MVA-kms to measure overhead km and underground cables (both inputs). This biases the model against DNSPs that have a high proportion of their network at higher voltages. These businesses will benchmark poorly, appearing inefficient, through the influence of the network design and the boundary between the transmission and distribution systems in different regions rather than any productivity difference.*[17]

In conclusion AAD reiterates its position presented in its responses to the AER's draft annual benchmarking report and draft category analysis report, and in the arguments presented above, that the AER should remove 132kV dual function assets from the benchmarking analysis. The exclusion of these assets, that are to be regulated as transmission assets in the 2014-19 regulatory period, would allow for a more comparable analysis with other DNSPs (such as Victorian DBs) which have no 132kV assets

[17] Hueing, ActewAGL Productivity Performance Analysis, 30 September 2014, p 9

3.5 Customer requirements and expectations

AER question

ActewAGL stated in its regulatory proposal that their costs are affected by the requirements of some of their customers. ActewAGL said that because it is located in Canberra it has a high proportion of strategically important institutions which require a high level of security of supply.

We note that all service providers have customers with high security of supply requirements. Examples of these include hospitals, state parliaments, military installations, banks, stock exchanges, and telecommunications facilities.

There are no explicit regulatory requirements on ActewAGL Distribution to provide a higher level of security of supply to customers with special requirements.[6] Therefore, customer requirements will not lead to cost differences between ActewAGL and other service providers that are unrelated to efficiency. ActewAGL identified several ways in which servicing customers with special requirements will lead to higher ongoing opex such as difficulties in access, confidentiality agreements, and ongoing maintenance of additional feeders and substations.[7] As mentioned earlier, all service providers have customers with special requirements. Therefore to the extent that customers with special requirements impose costs on ActewAGL, they will also impose costs on other service providers.

Further, our benchmarking already makes an allowance for ActewAGL's higher customer expectations. The multilateral total factor productivity (MTFP) and opex multilateral partial factor productivity (MPFP) benchmarking has the number of customer minutes off supply as a negative output. This model applies a lower value of customer reliability (VCR) than ActewAGL has proposed. However, should a higher VCR be applied for ActewAGL (to account for the higher expectations of its customers) it would perform worse under this analysis. This is because a greater weight would be placed on the negative output of customer minutes off supply.

AAD Response

The AER's view that special security of supply requirements and expectations will not lead to cost differences between AAD and other DNSPs does not reflect the operating reality on the ground. AAD has previously pointed out to the AER that security of supply to strategically important customers is driven by agency policy, and in the case of international embassies, the laws of other countries. Examples of customers in this category include diplomatic missions, Department of Defence agencies, Commonwealth agencies including security establishments (such as ASIO) and high security commonwealth data centres.

When connecting customers with special security of supply requirements, AAD's connection policy requires customers to pay for additional costs which are above the least cost acceptable solution. Nevertheless, some customer connections require departure from usual business processes which result in additional costs which are then charged against opex or overheads. These additional costs may not be apparent until the engagement with a customer is well advanced, and therefore costs cannot be separately identified or easily quantified in advance.

A good example of this is the additional opex incurred by AAD in undertaking connection services for a foreign embassy. Compliance with technical regulation is a legal prerequisite for AAD to connect any installation to the network. In this particular case, the customer refused to provide access to the ACT technical regulator to undertake an inspection, delaying the AAD connection process and resulting in a series of meetings and protracted correspondence involving AAD, the ACT technical regulator, foreign embassy and the Department of Foreign Affairs and Trade. Consequently, AAD resources required to deal with that customer extended well beyond the customer connection officers and included AAD management, regulatory and legal personnel, resulting in additional, unforseen opex.

In its response to the AER's recent information request (AER027), AAD provided examples of ways in which servicing strategically important facilities and national capital institutions in Canberra is likely to result in higher opex costs for AAD. Customers who restrict access or delay connection processes result in higher opex on AAD. Recent examples of such customers are the commonwealth special building project [redacted] and currently the connection of a high security data centre operated by the Defence Department.

In addition to extra opex costs associated with connection services, there are a number of customers who for security reasons restrict AAD's operational access necessary for switching, inspections or maintenance, and consequently cause AAD to incur ongoing additional costs. For example, AAD has 16 customers (including ASIO, the AFP and Defence) that have in place access restrictions in respect of 53 AAD owned substations. The most common restriction is to require staff to notify or be accompanied by the customer's security staff when entering and exiting. The practical effect of the access restrictions is to delay entry/exit at the sites.

The majority of these sites are supplied from Telopea Park 132/11kV Zone Substation, where outage planning requirements exist to ensure that security of supply is maintained. AAD work that could potentially impact these customers are given special consideration which results in 'outage windows' that will force the work to higher cost periods such as weekends and nights. Contingency planning and work redesign can also be required depending on the complexity of the outages.

AAD has the following comments to make in relation to the AER's statement that there is no explicit regulatory requirements on ActewAGL Distribution to provide a higher level of security of supply to customers with special requirements.

AAD is required to work closely with its high security customers, and ACT and Commonwealth government agencies to ensure security of supply is maintained.

The principles agreed by COAG in the Attorney Generals *Critical Infrastructure Resilience Strategy* have been given legislative force in the ACT under the *Emergencies Act* 2004 (ACT) and in particular, the Emergencies (Emergency Plan) 2014 (No 1) made under the *Emergencies Act*. AAD is required under section 5.2(b) of the *Utilities (Emergency Planning Code) Determination 2011* (ACT) to implement an emergency management plan that is consistent with the ACT Government's Emergency Plan requirements.

Furthermore, as a member of the Security and Emergency Management Senior Officials Group (SEMSOG) established under the *Emergencies Act*, AAD has agreed to follow guidelines issued by the Attorney General's Department (AGD) in relation to protective measures and security controls at AAD infrastructure sites. AAD considers its security risk to be elevated due to its unique position of supplying a critical resource to the seat of the Australian Federal Government, therefore increasing exposure to security risks from both sophisticated state based and terrorist interests that other jurisdictions may not be exposed to.

In accordance with the principles established under the *Critical Infrastructure Resilience Strategy* and the *Critical Infrastructure Protection Risk Management Framework for the Identification and Prioritisation of Critical Infrastructure*, the majority of AAD's zone substations in Canberra have been identified as 'critical infrastructure,' recognising the importance of maintaining a high level of supply security to government agencies and the city of Canberra.

On 12 September 2014 the Prime Minister increased the national security alert from 'medium' to 'high' meaning there may be imminent risk of a terrorism threat. Given that terrorism threats have been made against the Australian Government, the risk of a terrorist event in Canberra is very real. Although there has been no direct threat against AAD infrastructure, AAD has in place up-to-date emergency management processes to ensure it is ready for any potential threat to infrastructure, including emergency supply arrangements, disaster recovery plan and security arrangements.

Ensuring this emergency response capability and compliance with AGD guidelines for a 'high' national security alert is putting additional pressure on AAD's property and security resources. Specifically, opex is being impacted by requirements to deploy additional security resources and ensure increased vigilance at AAD infrastructure sites, tighten access controls, review response procedures and risk management planning, increase security screening and increase AAD employee awareness via training programs and internal publications.

3.6 Additional regulatory obligations, vegetation management, safety and taxes

AER question

In its submission on the benchmarking report ActewAGL notes that additional regulatory obligations, vegetation management, safety and taxes may adversely affect its benchmarking performance. [p.3] We accept that this might be the case – however ActewAGL has not provided evidence to support this claim. We request that ActewAGL provide evidence it is at a cost disadvantage relative to other networks due to additional regulatory obligations, vegetation management, safety and taxes.

AAD Response

As outlined in its regulatory proposal, the environment in which AAD operates includes critical and unique elements that impact significantly on capital and operating expenditures. A major element is the ACT urban planning and development, including Canberra as the *Bush Capital.* As the Minister noted in the foreword of The ACT Strategic Bushfire Management Plan[18]:

> *Bushfires are an inevitable part of living in the ACT. Canberra is described as the bush capital for good reason with forest and grassland woven through its urban areas. Along with the rural areas and the mountainous and forested landscape to the west and south, living in the ACT means we live in or near an environment in which bushfire is a natural occurrence.*

The ACT Nature Conservation Strategy 2013-23 "embraces" the idea of the Bush Capital and suggests a range of programs for native biodiversity to flourish in urban areas.[19] The Canberra urban forest is one of the largest in Australia containing over 730,000 trees.[20] These forested areas are also the predominate location for zone substations (due to planning rules regarding the sub-transmission network remain out of sight) resulting in higher reactive maintenance costs than other urban networks in less treed environments.

Any analysis of ActewAGL Distribution's vegetation management program must take these unique elements of the operating environment into account.

Objective of ActewAGL Distribution's Vegetation management program

ActewAGL Distribution manages vegetation in proximity to network assets across the ACT with the objective to:

- Ensure safety to the public and ActewAGL employees;
- Reduce the risk of initiating a fire and consequent damage to property of the environment;
- Minimise vegetation related power outages and maintain a reliable electricity supply; and
- Protect the integrity of ActewAGL's electricity network.

These objectives are consistent with the operating expenditure objectives in the National Electricity Rules:

(1) meet or manage the expected demand for standard control services over that period;
(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

[18] Emergency Services Agency 2014, *The ACT Strategic Bushfire Management Plan*, p.6

[19] Environment and Sustainable Development Directorate 2013, *ACT Nature and Conservation Strategy 2013-23*, p.2

[20] Minister for Territory and Municipal Services 2014,Media Release:*2,800 trees planted in 2013, 10 January*

(i) the quality, reliability or security of supply of standard control services; or
(ii) the reliability or security of the distribution system through the supply of standard control services

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of standard control services; and
(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services.

Scope of Vegetation management and vegetation clearance

As reflected in the operating expenditure objectives and AAD's vegetation management objectives, AAD is responsible for the safe operation of its electricity distribution network. Consequently, ActewAGL Distribution is responsible for vegetation management across its electricity network. Effective vegetation management also improves the quality, reliability and security of supply delivered by AAD.

The scope and responsibilities for vegetation management are as follows:

- Rural areas: AAD is responsible for vegetation in close proximity to network assets in natural areas, specifically national parks, nature reserves, special purpose reserves and Namadgi National Park – or more generally "rural areas".
- Urban areas: AAD inspects vegetation in proximity to network assets to ensure the safe operation of the electricity network. However, vegetation clearance responsibility does not always rest with AAD depending on the vegetation location and its attributes. Responsibility for vegetation clearance rests with:
  - The ACT Government Territory and Municipal Services (TAMS) for unleased public land
  - The landholder for private land;
  - AAD for vegetation that "pre-existed" network facilities.

  Vegetation on national land is dealt with on a case by case basis through direct contract with the National Capital Authority.
- Urgent clearance: AAD is responsible for any urgent clearance that needs to be undertaken. These costs cannot be recovered from the ACT Government or the landholder even if the vegetation is on unleaded public land or on private land.

ActewAGL Distribution's Vegetation Management in Urban Areas

To ensure the safe operation of the distribution network, ActewAGL Distribution's urban vegetation inspection team inspects all urban low voltage service power lines on a 3 year cycle.

The urban inspection team inspects around 44,000 properties each year. Urban high voltage lines are inspected on a 2 year cycle using LiDAR.

The inspection process

For vegetation on private land, prior to inspection the property occupants are advised that inspections will commence in 7 days. If vegetation is found encroaching the minimum clearance distances then the occupants are issued a notification to clear the vegetation. A second inspection is carried out 21 days after the initial notification. If the encroaching vegetation has not been cleared ActewAGL Distribution organises the clearing and charges the cost of the work to the occupant of the property. Each year, ActewAGL Distribution typically issues about 10,000 notices to private land holders in urban areas, or 20 percent of all properties inspected each year.

The notice issued requires occupants of the properties to clear vegetation to no less than the minimum clearances set out under the Utility Networks (Public Safety) Regulation 2001. Although the notice suggests trimming trees an extra distance away to allow for regrowth, this is not a regulatory requirement. As a result, occupants often chose to carry out limited clearances shortening the time taken for vegetation to again encroach within clearances of overhead lines. This creates another cycle of additional inspections and increasing costs.

A similar process is in place for unleased public land. ActewAGL Distribution issues notices to TAMS to clear vegetation. If the encroaching vegetation is not cleared, ActewAGL Distribution undertakes this clearance and invoices TAMS for this cost. Forecast recoverable vegetation clearance costs have been removed from the forecast operating expenditure.

Measures to maintain the efficiency of the urban inspection program

To lower vegetation management costs in urban areas targeted advertising campaigns are conducted. The key message is to keep trees and vegetation 1.5 meters clear of power lines, poles and ground-mounted assets. These programs encourage property occupants to be proactive in maintain vegetation on their land reducing the number of notices issued in urban areas increasing inspection rates and in turn lowering the costs incurred. In the absence of ActewAGL Distribution continuing to run these campaigns, vegetation management costs would be higher. These costs are not included in the vegetation management projects in ActewAGL Distribution’s forecast operating expenditure.

ActewAGL Distribution has also improved the productivity of its vegetation management team with the introduction of a new system that allows vegetation inspectors to wirelessly log the required inspection information and issues notices to occupants as inspections are conducted.

Urban vegetation management costs

ActewAGL Distribution forecast inspection costs using a bottom up approach. The forecast is based on the number of properties expected to be inspected. Based on past experience ActewAGL Distribution estimates about 20% of all properties inspected will be issued a notice.

The principal driver of costs of urban vegetation management is the labour cost incurred in conducting inspections. ActewAGL Distribution has estimated that the urban inspection program will require about 14,400 labours hours annually.[21]

Overall, although ActewAGL Distribution is not responsible for vegetation clearance in urban areas extensive vegetation management is still necessary to ensure the safe and reliable operation of the electricity network. In total urban vegetation management costs make up almost 50% of ActewAGL Distribution's forecast vegetation management operating expenditure, at around $1.8 million per year.

Rural Areas

In rural areas ActewAGL Distribution has full control of the vegetation management in close proximity to networks assets. ActewAGL Distribution takes advantage of this full control and ensures that any vegetation clearance is undertaken allows for three years of regrowth which in turn lowers costs.

Vegetation management in rural areas is forecast to cost approximately $1.2 million per year making up just over 30% of ActewAGL Distribution's vegetation management program. The majority of these costs are due to the clearance costs incurred.

ActewAGL Distribution's forecast cost is based on the historical costs of inspection using aerial and ground based inspections, including the cost of LiDAR and a works coordinator, to develop a bottom up forecast.

Urgent clearance

ActewAGL Distribution incurs the full cost in inspecting and clearing vegetation in urgent circumstances. ActewAGL Distribution cannot recover these costs from landholders or TAMS.

ActewAGL Distribution has forecast that annual urgent clearance costs will cost initially cost about $0.8 million, or 20% of total vegetation management costs, in total for both urban and rural areas. ActewAGL Distribution expects that the use of LiDAR will enable further efficiencies to be delivered. LiDAR allows a greater understanding of vegetation to be developed and improvements to be achieved in the planned vegetation management program. In turn these improvements will reduce urgent clearance costs.

In 2019, ActewAGL Distribution expects that urgent clearance costs will be about 60% of the costs incurred in 2013/14. Accordingly, ActewAGL Distribution has reduced forecast operating expenditure in an incremental manner from 2014/15 through to 2018/19. Forecast costs have been stepped down by 10%, 20%, 25% 35% and 40% in each year of the regulatory control period relative to the cost estimate for 2013/14.

[21] Allocation of hours against each vegetation management project is not available in all prior years; however urban vegetation inspections used the majority of all vegetation management hours. In 2013/14, 2012/13 and 2011/12 17,400, 20,496 and 15,920 hours were logged to vegetation management projects.

3.6.1 Taxes

In relation to taxes, AAD's understands that the AER has excluded the costs for the Feed-in-tariff and the UNFT in its benchmarking data is satisfied with that this is appropriately done. As noted above, however, the AER should also exclude the Energy Industry Levy which is a jurisdictional scheme that only affects AAD.

3.6.2 Safety

The implementation of the WHS Act 2011 (ACT) imposed an increased regulatory burden on the ACT compared to most other jurisdictions as NSW (OHS Act 2000 & Regulation 2001) and Victoria (OHS Act 2004 & OHS Regulation 2007) already had many of these more stringent requirements contained with their pre-harmonised OHS legislation (for example in relation to the obligations applicable to contractors).

Section 8.5.3.4 of AAD's regulatory proposal details additional expenditure on safety improvement during the 2009-14 regulatory period that was required to ensure all changes were implemented to the standard required by Work Health and Safety Regulation 2011. The 2010 Deloitte safety review of AAD's safety and health programs identified significant scope for improvement against industry best practice, suggesting a 'catch up' was required. This combined with the cost of compliance with the new WHS Act 2011 AAD has driven up expenditure on safety during the 2009-14 regulatory period and was likely to have resulted in proportionately higher costs compared to other DNSPs.

AAD pointed out in its response to the AER's draft annual benchmarking report that this increase in opex (input) could not be expected to lead to an increase in outputs under the AER's benchmarking model. Importantly, this does not imply that AAD's base year level of expenditure is inefficient, or that by incurring additional expenditure in the 2009-14 regulatory period to address important safety issues, AAD has not responded to incentives. AAD was aware of the EBSS penalty that it would incur as a result of spending additional opex on safety improvement programs during the 2009-14 regulatory period, and did so because it was absolutely necessary. Therefore, AAD did respond to the incentives in place at the time .

4 Specific capital expenditure questions raised by the AER

4.1 Investment frameworks, requirements and processes

AER question

How does ActewAGL ensure that ActewAGL's investment frameworks, requirements and processes comply with the current rules, regulations and standards? What systems do ActewAGL have to ensure compliance?

AAD Response

Governance of Capital Investment Projects

At the highest level, AAD has a corporate investment framework including corporate policies, delegations manual and planning / approvals processes to ensure that capital investment has an effective governance, prudency and efficiency framework. There are two approaches adopted by AAD to manage capital investment: one is an existing framework for managing minor or less complex capital investment with delegation levels, investment and accountability for decision making. The second is use of Project Boards specifically for large more complex CAPEX projects.

Role of AAD Board – Governance of Capital Investments

AAD's CAPEX activities are supported by the general risk management framework and the legal compliance framework. These frameworks are:

- a comprehensive, integrated and effective Risk Management Framework (RMF) consistent with AS/NZS ISO 31000:2009 that supports business resilience
- a comprehensive, integrated and effective Legal Compliance Framework (LCF) that conforms with AS 3806.2006

General Capital Expenditure Investment Guidelines

There is a delegation manual and authorisations specific to capital expenditure and maintenance. The capital expenditure for project approvals has bands of delegation levels [redacted] (An extract from the delegations process is given below in Figure 4.1).

Key documents that set out the governance and approvals framework for capital expenditure are:

- Business Planning, Project Planning, Project Approvals, Budget Management and Financial Forecasts, Networks Division Management System procedure no: EN 4.09 P2, version 3.0, effective 16 February 2011. [note: this document is being reviewed as part of normal policy review]

- AAD Corporate procedure 9.8 P1- Delegations of authority, Policy Custodian: Chief Finance Officer, Division: Finance and Resources, 1 July 2013
- Asset Management Commercial Risk Framework Policy – Expenditure, Policy Custodian: General Manager Asset Management, 1 July 2014

AAD Board approves expenditure (is responsible for release of funds) in excess of $5.5 million based on business cases with a capital value in excess of $5.5 million, this and other authorisation levels are shown below.

Figure 4.1 Authorisation levels for Project Expenditure Approval Authorisation levels for project expenditure approval

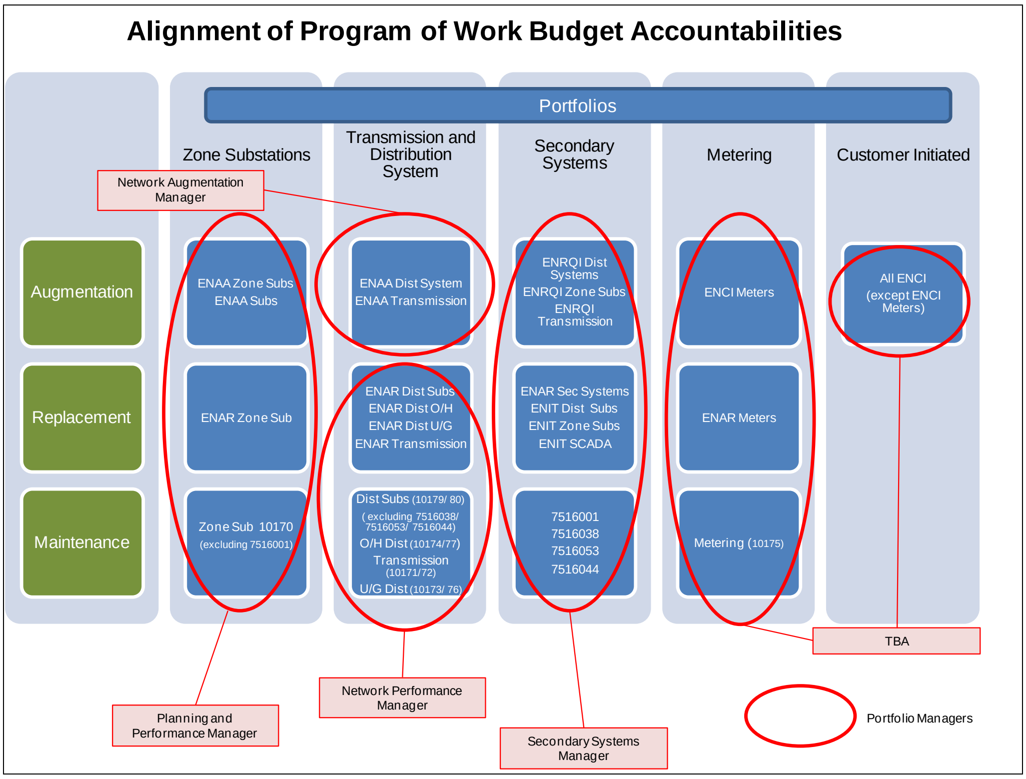
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]

Use of Project Boards

AAD established Project Boards and project management best practices—based on Prince2 methodology—for prudency, efficiency and the governance of major projects. AAD considers that large CAPEX investment projects are best delivered through alliance contracting and not using a 'business as usual' project approvals structure. Key stakeholders are brought together under the umbrella of the program board to make decisions as a group, thereby ensuring the needs of key stakeholders are met and the delays associated with serial or multi-layered decision-making are overcome. This is in keeping with current good practice in capital project governance.

In addition AAD has adopted the PRINCE2 project management methodology, and have trained relevant people as PRINCE2 practitioners. The project delivery function has also been improved with the introduction of portfolio managers and end to end definition of responsibilities and governance. An extract from the "New Program of Work Implementation Process" is given as Figure 4.2.

Figure 4.2 Extract from Work Implementation Process



Application of Project Boards – OSR Project

AAD has recently implemented the transition of a number of legacy IT/OT systems (Non-Network CAPEX) program under the "Operational Systems Replacement (OSR) Program" using the Project Board Governance framework.

Program of Works Committee

The role of the Program of Work Committee (POWC) monitors the delivery of programs of work. The role of the POWC is to ensure the project is delivered and address risk within financial and resource constraints.

- Review the investment options for AAD across capital, operations and maintenance programs; to meet corporate and stakeholder objectives and address risks within financial and resource constraints.
- Review the high-level milestones and tolerances with which programs and projects must be completed
- Monitor the progress to plan across the projects and programs as part of the annual Program of Works.

Legal obligations & compliance monitoring

AAD has a rigorous process to ensure that legal and regulatory obligations arising from the relevant legislations are monitored, impact accessed and communicated within the organisation. AAD invested in purchasing and maintaining the CMO software, which is a comprehensive database of obligations. The business owners within AAD for the CMO data base are the Legal & Secretariat Division (LSD) and the LSD group stay central to the process. New or changed obligations are captured using updates from an external legal service provider who provide a quarterly update of the relevant legislation via the CMO Compliance Software. Sources include:

- CMO compliance software – updated quarterly
- Always safe compliance Guides – Updated quarterly
- Lawlex – customised for specific interest, updated as legislation changes
- Licences/Contract renewals

The most comprehensive and relevant amongst this to CAPEX investment is the CMO. There is a comprehensive legal compliance process which explains the process of capturing legislative changes, assess impact on the business, communicate changes within the organisation and specifically to responsible business owners and determine course of action. There are three internal process documents that are relevant in elaborating AAD's legal compliance process, risk management and policy.

These changes are discussed with the LSD and the regulatory compliance group and the business owners are alerted to changes in obligations (The CMO database has responsibility for legal compliance allocated to various groups and business owners). The regulatory and compliance group follow up with business owners to monitor progress in maintaining compliance. This process is carried out diligently and is important in maintaining the ISO rating. A draft high level diagrammatic representation of the CMO process flow is provided as a table (extracted from AAD Corporate procedure 6.0 P2 – Legal Compliance Process) detailing the process is providing as Table 4.1.

The key process document that sets out AAD's legal compliance procedure is:

- AAD Corporate procedure 6.0 P2 – Legal Compliance Process, Policy Custodian: General Counsel and Board Secretary, Division: Legal & Secretariat, 18 January 2001 (reviewed 31 January 2014).

Change of legislation

The AER's comment was noted regarding the incorrect reference in the SRP to the Supply Standards Code 2000. AAD was aware of the changes to the ACT Electricity Distribution (Supply Standards) Code 2013 (the code) effective (and simultaneous revoking of the ACT Electricity Distribution (Supply Standards) Code 2000. For the AER's information AAD has developed a plan to address the material implications of the 2013 changes which spans many years.

Further, these changes do not have any short term or immediate impact on AAD's 2014-19 CAPEX program. For example, there are no SAIDI/SAIFI implications arising from the 2013 changes since the most significant change relates to nominal voltage change to 230 volts (which is within the previous operating voltage range). It is to be noted that AAD made submission to the ACT Government leading up to the change of the code. AAD notes that the code does not have the obligation on AAD to ensure supply capacity (clause 8.1, Levels of Supply Capacity – contract to ensure supply capacity of the code). AAD does not believe that revoking this clause has a material impact on the CAPEX forecast over the next regulatory period.

There are numerous references to the code in the SRP and an implicit reference in section 4.5.2.2 and a direct reference in section 6.4.1 to the code nominating 2000. AAD was aware of the 2013 code changes notwithstanding the reference to the 2000 Code in the SRP, which is a referencing error.

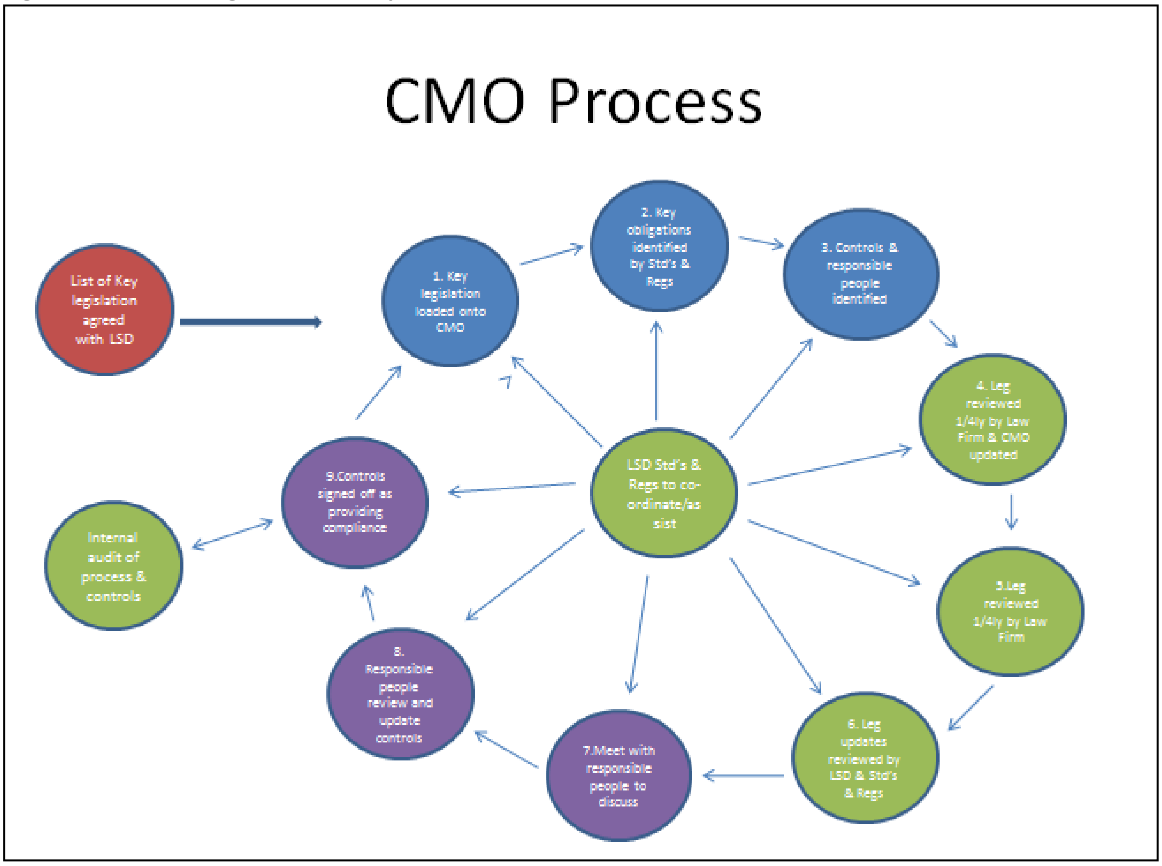
Table 4.1 Legal & Compliance Process

Process Step No.	Task	Responsible Manager
1	*Maintain obligations database* AAD maintains a database containing all relevant federal, state and territory legal obligations applicable to AAD's operations. The obligations are linked to specific divisional business processes and documentation to demonstrate that the obligations have been assessed against operational activities and actioned accordingly. The system also contains work flows to enable the assignment of actions when obligations are amended.	Manager Legal Compliance
2	*Capture New or Changed Obligation* Obligations supplier(s) provide a regular update of all new and amended legal obligations relevant to AAD's operations. Sources include: • CMO Compliance Software - updated quarterly • Always Safe Compliance Guides - updated quarterly • Lawlex –individual users customise for updates of interest, provided as and when legislation changes • Licences / Contracts Staff in many areas may also become aware of significant changes to legal obligations affecting their activities through Government consultation, industry groups and various other networks / websites/ sources and are required to notify these to the Manager Legal Compliance.	Manager Legal Compliance (for general legal obligations) Corporate Quality Manager (for HSE obligations All staff
3	*Identify associated business processes* In the event that AAD is notified of an amendment to an existing obligation, the obligations management database identifies all business process owners whose processes are affected by the change and automatically sends a notification alert requiring the process owner to review associated process documentation. Automatic alerts of all new or amended legislation are also sent to LSD, EHSQ, and Divisional Compliance Officers. These amendments are reviewed by each party to determine if a risk of misinterpretation by the business process owner exists or if urgent action is required (outside of regular team review) to address the change. If there is a risk of misinterpretation, the Deputy General Counsel provides clarification relating to the application of the amendment within Divisional	Business Process Owners Operational personnel in consultation with Deputy General Counsel

Process Step No.	Task	Responsible Manager
	processes and procedures.	
4	*Assess Impact of new / changed legislation* Upon receipt of a new or amended obligation, an assessment is made to decide whether it has any relevance or impact on the business, both from a legal and an operational perspective. Where new legal obligations are enacted, they are assessed against the entire suite of current divisional business processes to determine where updates are required to positively address the obligation. New obligations are linked within the obligations management database to any existing relevant divisional process documents. *Note: Please refer to process step no. 6 within this document in the event that a new obligation requires a new divisional procedural document to be developed to address the obligation.*	Divisional Compliance Officers in consultation with Deputy General Counsel Divisional Compliance Officers
5	*Determine Course of Action* A quarterly review of all new and recently amended obligations is convened by LSD with each Divisional Compliance Officer to ensure that new legislation is understood and correctly applied within divisional business procedures. The meeting is attended by the Deputy General Counsel, Manager Legal Compliance, and Divisional Compliance Officer's or their respective nominees. Relevant operational subject matter experts are invited as required, dependent on the legislation that has been changed. Minutes of the meeting are maintained by LSD reflecting applicability of the amendments to the relevant division. Where changes in obligations are notified to an individual by other means, and must be addressed urgently, the individual liaises directly with their Divisional Compliance Officer to ensure that all requirements are correctly understood.	Manager Legal Compliance- convening meetings. Deputy General Counsel – providing correct legal interpretation Operational personnel in consultation with Divisional Compliance Officer
6	*Update documents for new/changed obligations* Divisional procedural documents are reviewed and updated as required to meet the changed or new obligations. This is done in accordance with corporate and divisional document review and creation guidelines.	Business Process Owners

Process Step No.	Task	Responsible Manager
7	*Communicate changes and deliver training* Once amended process documents have been published, changes are communicated to all relevant stakeholders in accordance with divisional guidelines. Any necessary training is arranged and recorded and a copy kept by Business Process Owners in accordance with relevant document review and approval procedure.	Business Process Owners
8	*Everyday Supervision and Monitoring of Compliance* Operational supervisors, as a regular part of their daily activities, monitor and record compliance with approved policies, procedures, work instructions and other processes owned by them.	Business Process Owners
9	*Perform compliance reviews and audits* Monthly reviews of compliance against EHS legislation are performed using Always Safe Compliance Guide Audit Tools. Where possible, Compliance Guide Audits shall be scheduled to reflect the monthly EHSQ Communication Program across the business, see 7.5 P24 EHSQ Communications and Consultation Procedure. Annual reviews of compliance performance are conducted for non-EHS legal obligations. The legal compliance process is included in the program of regular audits of internal controls performed by Internal Audit.	Corporate Quality Manager in consultation with Divisional Compliance Officer Divisional Compliance Officer and Manager Legal Compliance Manager Assurance & Risk

Figure 4.3 Draft Diagrammatic Representation of the CMO Process



Technical Compliance

Figure 4.4 illustrates the process applied for determining prudency and efficiency in CAPEX investment. Investment in CAPEX falls into the following major categories:

1. Asset Replacement CAPEX
2. Network Augmentation CAPEX
3. Customer Initiated CAPEX

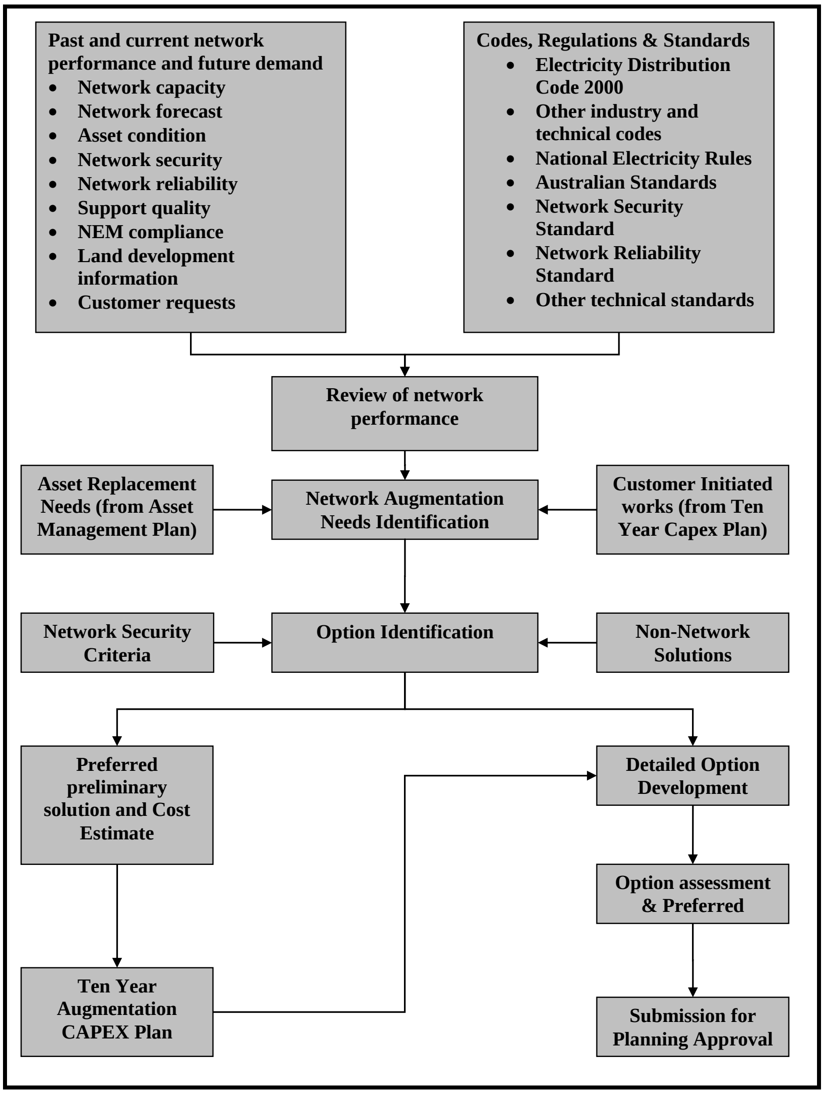
A significant proportion of AAD's asset replacement CAPEX (and OPEX) is now documented and supported by the implementation of RIVA and the internal algorithms within RIVA that generate the refurbishment / replacement CAPEX and OPEX forecasts. AAD has undertaken audits to understand the integrity of the RIVA algorithms and ensure compliance. The two independent audits are referenced below:

- SH43539.R012 - Audit of Riva Asset Recording System, SKM 24 January 2014
- Expenditure Forecasting methodology, SRP Submission – Analytics Group May 2014

The expenditure forecasting methodology has been submitted with AAD's SRP and it explains the details of algorithms used by RIVA. Therefore the process around how RIVA works is not discussed in this response. This document was prepared by the management consulting firm Analytics Group, under the guidance of AAD Distribution. Analytics Group has prepared this document with the express purpose of documenting the CAPEX and OPEX forecasting methodologies of AAD Distribution.

External obligations and internal criteria tend to be the main drivers of the larger, higher value projects such as zone substation upgrades and developments, as well as major 11kV distribution augmentation projects (also driven by customer supply obligations). The process for conducting studies that consider prudency by establishing a need for the project to meet a regulatory obligation or a customer requirement and the options considered to ensure efficiency in the solution is described in the process below. Both prudency and efficiency are considered throughout the project planning process – from the initial long term concept planning ("Network Augmentation Needs Identification" / "Option Identification") to the short term detailed works planning processes ("Detailed Option Development" / "Option Assessment").

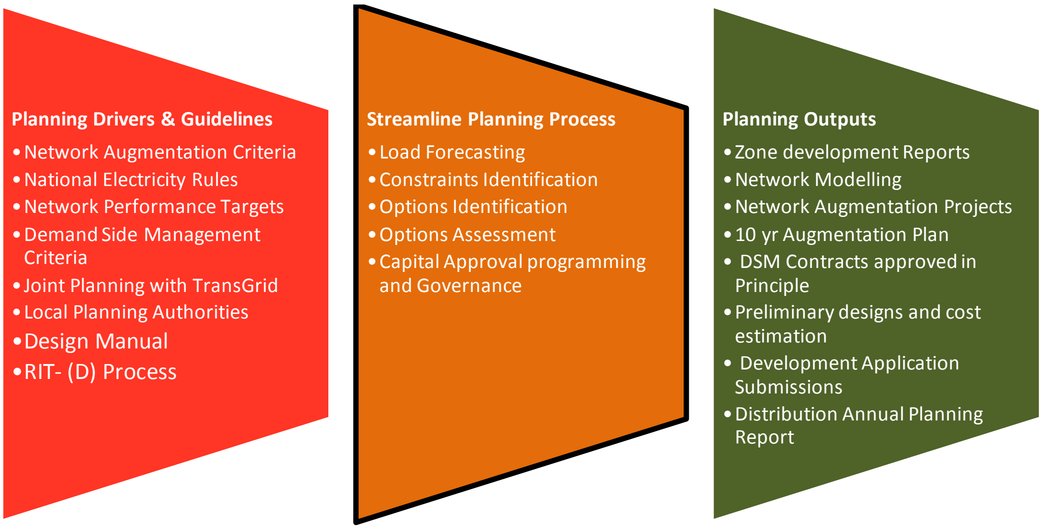
Figure 4.4 Technical Distribution Planning Process



The technical investment framework which ensures technical compliance in CAPEX projects consists of a series of process documents that cover the different CAPEX investments. AAD has a number of internal documents developed as an application guide based on "good industry practice" or planning criteria based on the externally imposed obligations arising out of the NER rules. Table 4.2 provides a list of internal process documents that ensure technical compliance is maintained in investment decisions.

Table 4.2 List of Internal Documents relevant to AAD's CAPEX investment framework

Documents	Scope or Purpose of the document
Asset Management Strategy Version Number Version 2.11 Effective date 23 May 2014	Asset Management Strategy for AAD Distribution defining strategic objectives and approach to the management of physical assets.
Augmentation Projects Review Checklist	Check list developed to authorise augmentation plans Augmentation checklist identifies if a need has been established in terms of identifying system limitations, such as overloads and constraints (joint planning if applicable) and project development plan consisting of a map of the project, in accordance with the planning methodology.
Analysed Program of Works 2014 09	This is an excel spreadsheet of the CAPEX augmentation projects, which are classified according to their criticality. This model considers the optimum capital replacement strategy based on trade-off between asset life of operation, replacement and maintenance costs. The capital replacement program is classified into discretionary and non-discretionary expenditure. ▪ Run to failure ▪ Condition monitoring ▪ Time scheduled
Distribution Network Augmentation Standard (26 May 2014),	The purpose of this Standard is to define the distribution network augmentation criteria for AAD's distribution network planning and expansion. The document sets out the Network security and reliability targets and the system capability definition. This standard supersedes following documents: 1.SR016 - Network Supply Security Standard, 2.SR018 - Network Augmentation Investment Criteria, and 3.EN 4.04 P07 - Distribution Network Reliability & Standard Supply Arrangements.
Distribution Network Planning & Expansion (26 May 2014)	This policy provides a framework for distribution network planning and expansion that applies to the electricity network's ten-year capital planning process for the development and implementation of network augmentation program and projects. 1. to streamline a systematic planning process which provides certainty in relation to approval of network expansion and augmentation to maintain the reliability of the electricity supply to consumers, 2. to provide principles and guidelines to make decisions that may offer alternative, cost-effective solutions for network augmentations to address emerging constraints, 3. to incorporate demand side management as an alternative to network expansion, 4. to ensure appropriate information is available for planners and external planning agencies.


Planning Drivers & Guidelines
• Network Augmentation Criteria
• National Electricity Rules
• Network Performance Targets
• Demand Side Management Criteria
• Joint Planning with TransGrid
• Local Planning Authorities
• Design Manual
• RIT- (D) Process
Streamline Planning Process
• Load Forecasting
• Constraints Identification
• Options Identification
• Options Assessment
• Capital Approval programming and Governance
Planning Outputs
• Zone development Reports
• Network Modelling
• Network Augmentation Projects
• 10 yr Augmentation Plan
• DSM Contracts approved in Principle
• Preliminary designs and cost estimation
• Development Application Submissions
• Distribution Annual Planning Report

4.2 Suitability of risk to business and consumers

AER question

How does ActewAGL determine the suitable level of risks to the business and consumers? How does ActewAGL translate the risk profile and risk appetite into an optimal level of Capex and Opex?

AAD Response

The response to questions 2 and 3 overlap as question 3 covers prioritisation of expenditure (capital rationing) which is closely related optimisation of CAPEX and OPEX based on risk.

Risk Profile/Appetite and Consumers

AAD has used the results of research into customer willingness to pay to quantify the consequences of changes in specific service levels that could result from alternative expenditures. As discussed in its SRP, these estimates have been considered as part of decisions in relation to potential overhead-to-underground conversion of the low voltage network, the proportion of planned (rather than reactive) maintenance on the network, and the appropriateness of service standards in relation to reliability. (pp11-13, 40-42)

CAPEX Replacement – Risk based Approach

A decision support model developed by AAD, "**Analysed Program of Works"** is applied to the 5 year replacement CAPEX to optimise the CAPEX replacement program based on OPEX costs and risk levels. This is not unlike the risk priority number implemented in RIVA. However, at this stage, RIVA is still under development as a complete decision tool to support CAPEX replacement. Therefore a parallel process of risk modelling is used to determine the CAPEX replacement strategy.

The 'Analysed Program of Works' model considers the **failure effect**, **risk** (likelihood, consequence and availability of effective mitigation measures**)** based on the determined failure effect for each asset under consideration, one of the following replacement strategies is adopted and an optimal time for replacement or monitoring is identified.

1. Run to failure
2. Condition monitoring
3. Age and condition based replacement with asset class life adjusted according to the failure effect

The equipment / asset class or if appropriate, the planned works is given a ranking under each of the following categories:

1. Failure effect,
2. Consequence;
3. Likelihood of failure

The combination of failure effect, consequence, the likelihood of failure and the availability of a mitigation strategy determine the risk level and the replacement strategy. In addition there is a column that selects if the replacement is discretionary or non-discretionary capital replacement. For example replacement of a capstan link (old and has exposed metal) operated in the wrong way can be dangerous, however there is a mitigation strategy is available, therefore this is' run to failure' and considered a discretionary expenditure.

The total capital replacement expenditure for the next regulatory period is $105 with $80.5 identified as non-discretionary expenditure and $25.4 M identified as discretionary expenditure. Of the discretionary spending, the low risk and discretionary spending for the budget is approximately 4% and the medium risk and discretionary expenditure is approximately 24% (see Figure 4.5).

[redacted]

Analysed Works of Program

The parameters used in the Analysed Program of Works model are listed below. The effects of failure of the asset "Failure effect" are classified into:

- Failure to protect operator
- Failure to supply power (supply interruption and duration)
- Failure to protect equipment
- Failure to protect public
- Failure to protect the environment
- Failure to provide operator access
- Failure of transformer tests

The consequence of the event is considered under the following categories:

- Financial damages, losses or costs
- Disruption to operations
- Damage to reputation or competitive position
- Health/safety incident
- Damage to the environment
- Legal/compliance breach
- Disruption to program/project

The likelihood of the event is considered under the following categories:

- Certainly
- Likely
- Possibly
- Rare

CAPEX Network Augmentation – Risk Based Approach

AAD has a risk matrix model applied in some PJRs; this risk matrix captures risks introduced by the projects or modified risk level on implementing the project. The risk matrix model largely identifies business risks and their consequences (e.g. commercial, financial, business continuity, legal compliance, environmental, loss of supply, etc.) with assigned levels of probability and consequence.

Broadly, such risk matrices have been applied to project justifications where managing business risks have been the key factor in determining the requirement for the project. A specific example is the business case for the installation of Remote Area Power System (RAPS) units for the remote communities of Gudgenby Homestead and Corin Dam, which replaces sections of an overhead long-rural feeder that was identified as being at high risk of initiating a bushfire.

A risk assessment was undertaken considering the number of fire ban days applicable to the area, modes of failures likely to result in a bushfire and the consequence of the modes of failure. The financial penalties likely to result from an a minor incident or a major incident were considered in identifying the level of risk to AAD as a result of not undergrounding or utilising Remote Area Power Systems (RAPS) to mitigate the risks identified. A summary of this case study is provided below

Case Study: Installation of Remote Area Power System (RAPS) units to replace sections of the Mathews and Reid feeders

Risk assessments undertaken by ActewAGL since the 2003 bushfire in the region has identified that there is potentially a **high risk** that sections of the 11kV single circuit overhead distribution lines Matthews and Reid servicing the remote rural communities, Gudgenby and Corin Dam, could cause bushfires.

The loads at Corin Dam and Gudgenby serve a few specialised purposes, such as the Dam operations, Telstra communications tower, and emergency operational centres and also serve accommodation complexes for park rangers, their families and community guests. The Corin Dam and Gudgenby loads have an average annual energy consumption of 12.2MWh and 14MWh respectively.

The [22]financial impact of causing a bushfire for ActewAGL has been assessed for minor to severe bushfires, ranging from $[redacted]. Based on these compensation values, the estimated cost of the identified section of the Matthews and Reid overhead line section causing a bushfire is estimated at [redacted] per annum over 25 years).

The specific cost for the identified section of Matthews and Reid lines, comprising of 107 poles, has been identified systematically by estimating the probability of ActewAGL equipment causing a bushfire on one of the 5 annual fire ban days, failure rates of components, failure modes that are likely to cause a bushfire and the type of vegetation growth underneath the lines.

To reduce the risk of bushfire whilst continuing to provide reliable supply to the remote communities, two alternative **credible options** were developed and compared against the "status quo". A high cost solution identified was to underground sections of the lines and a lower cost option identified was the installation of a remote area power system (RAPS) module. The RAPS solution is an off grid stand-alone generation unit, in this case, consisting of an array of Photovoltaic (PV) cells, diesel generator and battery storage.

[22] The bushfire damage estimate for ActewAGL ranging from minor to severe bushfires is based on the 2003 bushfire compensation and claims assessment, escalated to 2013 dollars.

A brief summary of the costs of the options are given below.

Table 4.3 Summary of options cost

Supply Options	CAPEX Cost	OPEX Cost	NPV
Option 1 Status Quo	[redacted]	[redacted]	[redacted]
Option 2 UG existing overhead lines	[redacted]	[redacted]	[redacted]
Option 3 Off-grid RAPS	[redacted]	[redacted]	[redacted]

Note: Costs are 2012/13 direct costs only and do not include overhead costs.

The recommended solution is to install the RAPS (option 3) and de-commission the existing overhead lines to Gudgenby Homestead and Corin Dam. This option gives the lowest NPV of the options considered taking into account the risk factor of compensation due to a bushfire being included in the status quo (option 1).

ActewAGL believes that the installation of a RAP system at these locations represents a genuine and credible non-network option that can be practically deployed. A barrier to the consideration of genuine non-network solutions or demand side management has been to find a solution capable of being practically deployed and sufficiently reliable for the purpose. This initiative is in line with the National Electricity Rules framework requirements to consider credible non-network solutions and encourage utilities to make effective choices to manage risk.

The option to underground (option 2) provides higher reliability than option 1 and significantly reduces the risk of ActewAGL's assets causing a bushfire, however the option is capital intensive and is not considered to be prudent or efficient in light of alternative solutions available.

The option to maintain "status quo" is provided as a reference for comparison of costs however, considering risks, it would be imprudent and risky for ActewAGL to not explore alternative solutions and may be viewed by regulators and legal entities as being non-proactive (reactive), if alternative supply solutions are only considered after the occurrence of a bushfire.

ActewAGL has held consultations regarding the proposed solution with the ACT Department of Parks, Conservation and Lands, who own the housing complexes for park rangers and is the only

[23] This figure includes a 30% contingency from the original figure of $210,000.

major customer in the areas. The ACT Department of Parks, Conservation and Lands, is supportive of the efforts to mitigate bushfire risk and introduce local renewable generation.

ActewAGL will install, own, operate and maintain the RAPS module. Changes to the [24]distribution loss factors should provide reduced use of system charges to the customers in the area, due to low expected network losses as a consequence of being off-grid.

Together with the RAP system, it is anticipated that the load will be reduced by 40% following the installation of energy efficient appliances (demand side management) and modifications to the accommodation for reduced heating consumption.

This project justification report recommends the RAP solution which is assessed to be prudent and efficient. The choice of solution is effective in managing ActewAGL's risk and financial exposure. This recommendation is congruent with ActewAGL internal policy of cost effectively managing financial and public safety risks originating from ActewAGL owned assets.

Figure 4.6 Extract of the modes and cost of failure of the bushfire risk on the Corin Dam and Gudgenby lines from the RAPS augmentation report

[redacted]

Energy at Risk modelling to optimise timing of CAPEX

Where CAPEX investments require more granularity in the assessment of timing for a project, energy-at-risk modelling have been used (refer AAD's 2009-14 regulatory reset) to successfully demonstrate the economic justification for the replacement of the 11 kV switchboards at the Civic zone substation. The relative small size of the AAD system and the infrequency with which major substations or feeders become overloaded does not present many opportunities to apply energy-at-risk modelling.

Jacobs (formerly SKM) applied energy-at-risk modelling to AAD's 2009-14 regulatory reset to successfully demonstrate the economic justification for the replacement of the 11 kV switchboards at the Civic zone substation.

[24] It is expected that ACT customers at Corin Dam and Gudgenby will not be subject to Transmission Use of System Charges and Distribution Use of System Charges.

Due to the relative small size of the AAD system, and the infrequency with which major substations or feeders become overloaded there were not many opportunities to apply energy-at-risk modelling. Looking forward at the 2014-19 regulatory period, there are a small number of potential opportunities to apply energy at risk modelling. The relevant planning processes, as provided to the AER, have been applied to these projects in the SRP and the Energy at Risk Modelling approach will be considered when the respective project becomes part of the annual works program planning phase (12 to 24 months prior to the project commencement) as part of AAD's Capital Works Approval processes, Projects of note that are included in the SRP are:

- The timing of the installation of an additional transformer at Belconnen zone substation
- The timing of the installation of the second transformer at Eastlake
- The timing of the installation of the second transformer at Molonglo

In future, AAD will consider applying energy-at-risk modelling to suitable projects to optimise the timing and capital expenditure. In most cases the time it takes to transfer load to neighbouring substations has been calculated in relation to maintaining reliability on the core grid and customer supply. There hasn't been, and there is unlikely to be in the future, the same opportunity as DNSPs in Victoria to use this concept in a pragmatic manner on a large scale.

Prioritising CAPEX using the Risk Priority Number in RIVA

AAD uses RIVA asset management software to perform a range of functions, including the forecast of significant CAPEX and OPEX projections made by AAD. [25] RIVA also pulls information from the asset management system, Works, Assets, Solutions and People (WASP[26]) for up to date maintenance data, ensuring work schedule projections are based on relevant data (i.e. asset condition) and trends.

At its core, RIVA uses this data to inform a series of algorithms that provide an optimal CAPEX replacement/augmentation program and maintenance work schedule. These algorithms are based on the fundamentals of risk based assessment. The two risk considerations include **probability of failure (POF) consequence of failure (COF), and detectability (this takes into consideration whether failure can be easily detected, the harder it is to detect failure and cause damage the higher the risk rating)**. The three factors combine to determine a risk priority number. Each asset is subsequently ranked according to the exposure[27] that the distribution network and customer would experience if the asset failed. Below is an extract from the Expenditure Forecasting Methodology given as Figure 1 to provide context to the process used by RIVA in risk prioritisation.

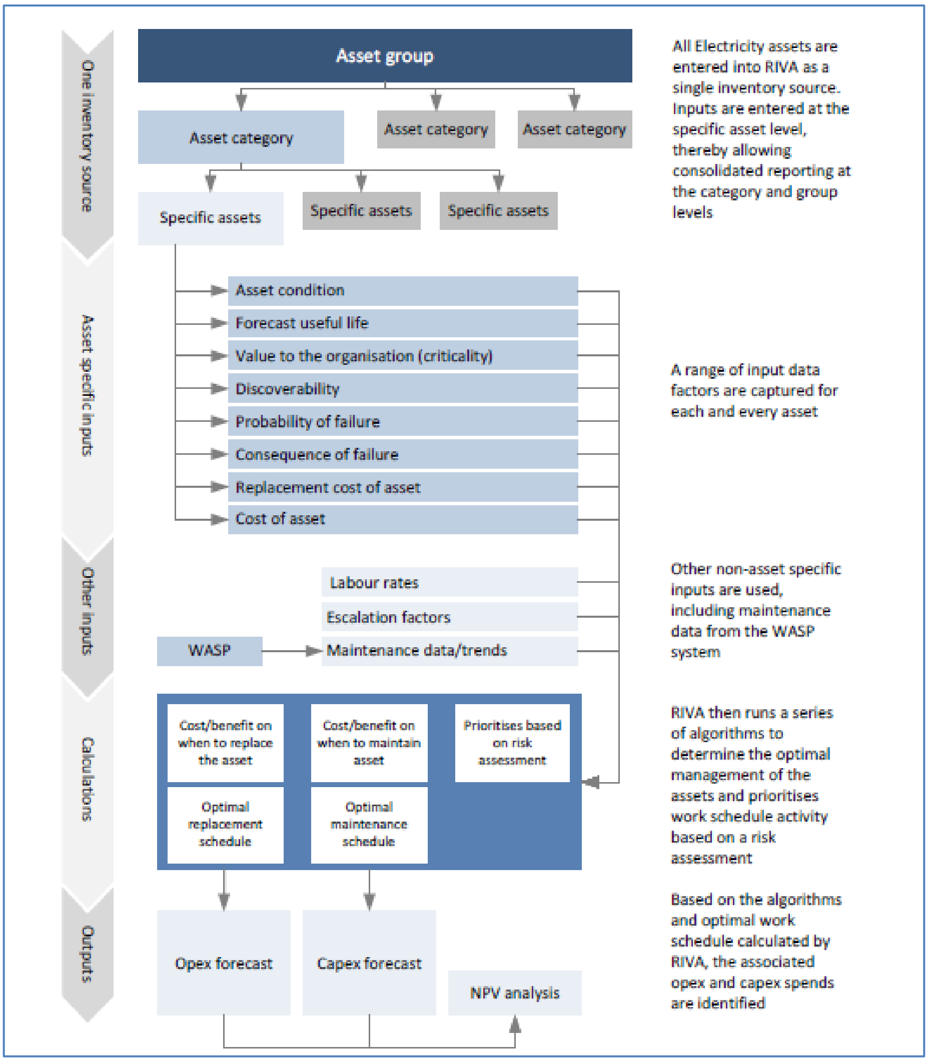
[25] Expenditure forecasting Methodology, Analytics Group – May 2014

[26] The integration to CityWorks is being completed in 2015 to supersede the outdated WASP system

[27] The level of acceptable exposure is holistically addressed in the commentary which forms part of the earlier response to this question.

Note: Detection rankings have not been fully populated in RIVA yet; only probability of failure (POF) and consequence of failure (COF) are in use. Figure 4 shows a working model of RIVA and Figure 4.7 shows the full functionality of RIVA's risk priority number including 'detection controls' and 'detection', which are not functional yet.

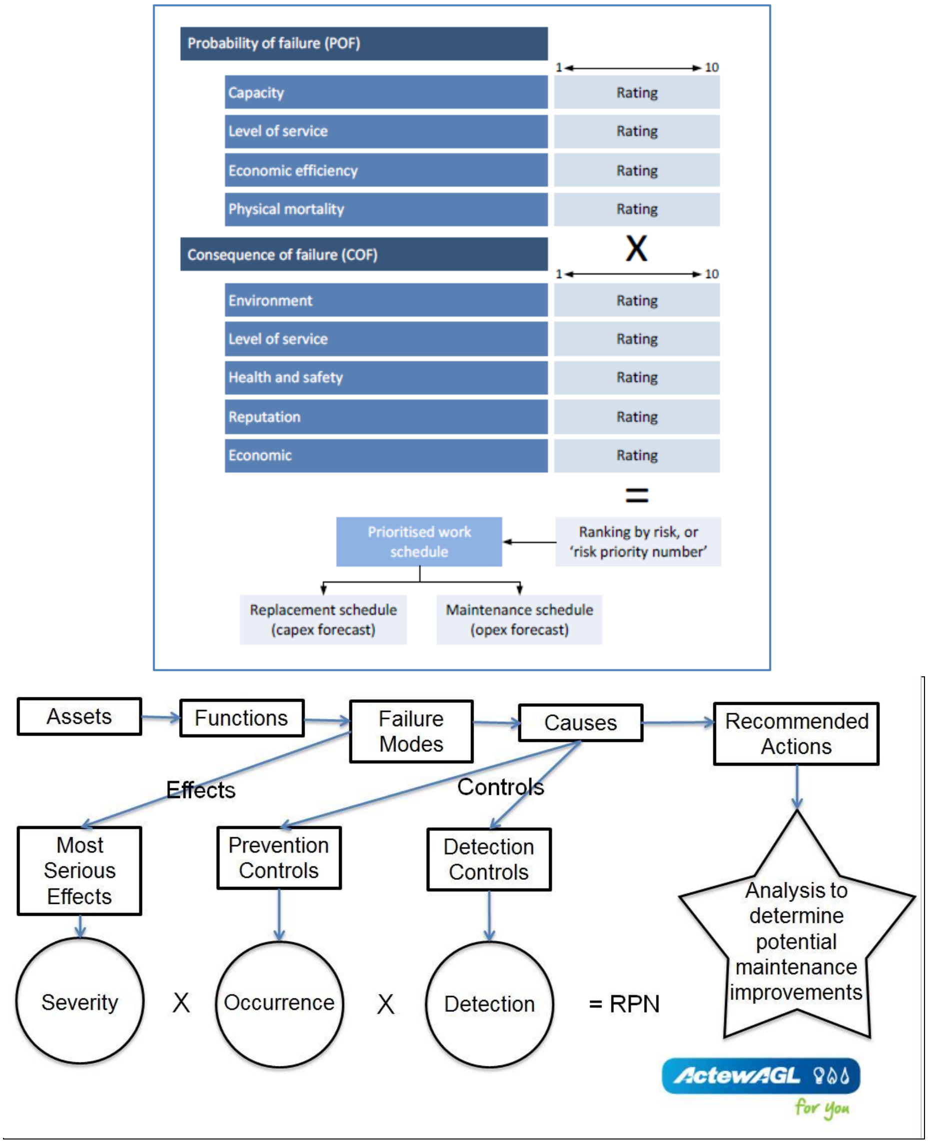
Figure 4.7 Overall processes for RIVA



RIVA then produces a risk priority number (RPN) value for each asset in the inventory. This value is used to prioritise inspection frequency, insurance valuations, and environmental mitigation strategies; and also rank competing events and activities. Ultimately, RIVA can provide a replacement/augmentation program and maintenance work schedule which includes the period covering the upcoming regulatory period. Using this information, RIVA generates optimised and prioritised ten year CAPEX and OPEX forecasts for each specific asset. These forecasts are then consolidated at the category and group level for summary level reporting. The method by which RIVA accomplishes this is set out below.

The method by which AAD Distribution asset renewal/replacement and maintenance activities are prioritised is a critical function of RIVA. Essentially, a series of factors contributing to probability and consequence of failure are each rated by maintenance personnel and engineers on a 1 to 10 scale, with 10 being the most severe rating. When combined, these factors determine the asset’s risk priority number (risk score). This forms the basis for work schedules on which the OPEX and CAPEX forecasts are based.

Figure 4.8 Risk prioritisation in RIVA



Using the information and the outputs of RIVA, discretionary projects over $100,000 in value are subject to net present value (NPV) assessments, providing for cost-benefit and analysis. This is documented in the Asset Specific Plan (ASP) and allows a 5 year life-cycle cost estimate comparing asset replacement with alternate options of maintaining the asset over the same period.

RIVA is a new asset management initiative and has not been fully populated. The full functionality of RIVA will be established and utilised over the next regulatory period to perform more sophisticated modelling of CAPEX replacement and augmentation prioritisation. Until such time as RIVA is fully functional the optimisation of CAPEX is completed outside of RIVA. The methods used for this 2014-19 regulatory submission are described in the 'CAPEX Replacement Risk based Approach' and 'Feeder Sensitivity Analysis' commentaries as part of the response to this question and are illustrated with some examples.

Example: CAPEX Investment, Reliability Improvement and STPIS Incentive

This case study demonstrates the use of scenario approach to assess if there are any significant STIPS benefits in undertaking reliability improvements.[28]

The worst performing 11kV Macrossan feeder was chosen as the sample to assess if the capital investment required to improve reliability resulted in a net STPIS benefit. The scenario where reclosers are used to sectionalise the feeder and the expected SAIDI, SAIFI benefits of sectionalising the feeder were analysed. It was found that for an investment of $193,700 the expected total reduction over 5 years in SAIDI and SAIFI is 0.065 and 0.049 respectively. This equated to an annual average of 0.0129 and 0.0099 (respectively) and an annual STPIS saving that did not outweigh the capital investment and STPIS benefits themselves were marginal. The NPV feeder sensitivity analysis concluded that it was uneconomic to invest in reclosers as the STPIS benefits were marginal and did not outweigh the cost of the installation. The example demonstrates AAD's analysis of risk using a scenario based approach.

AAD has a number of short rural/urban feeders with many branches, therefore using reclosers to sectionalise and improve reliability is not a strategy that works well in a number of cases. Distribution network companies that have longer feeders tend to benefit from using re-closers to provide increased reliability.

4.3 Expenditure priorities and resource limitations

AER question

Given the resource limitations, how does ActewAGL set priorities for its expenditure projects and programs, across all expenditure categories?

AAD Response

[28] Investment in Feeder Reliability Improvement Projects for STPIS, Version 1.0, 26 March 2014

Scope of Response

The response to Questions 2 covers some examples of CAPEX expenditure prioritisation and this response to Question 3 should be read in conjunction with the AAD's response to Question 2. This response provides examples of CAPEX prioritisation for network CAPEX expenditure. The SRP provides further details of prioritisation projects; references to relevant sections of the SRP are provided in the response.

Prioritisation and CAPEX – OPEX trade off

In response to Question 2 from the AER, AAD has provided specific instances where AAD has demonstrated prioritisation of CAPEX replacements and demonstrated detailed consideration of CAPEX-OPEX trade-offs factors in decision making. To reiterate the key relevant points, the following prioritisation principles were illustrated with examples in AAD's response to Question 2.

1. "Analysed Program of Works" model is used to categorise CAPEX replacement budget into 'discretionary' and 'non-discretionary' expenditure for the five year forecast period. Further, the discretionary CAPEX replacement budget is classified into' low risk' & 'discretionary' expenditure (comprising ~4% of the total CAPEX replacement budget) and 'medium risk' & 'discretionary' expenditure (comprising ~24% of the total CAPEX replacement budget). This is an example of prioritisation and may be used to prioritise expenditure under capital rationing constraints.
2. The "Analysed Program of Works" model was illustrated with an example of an OPEX-CAPEX trade-off decision to replace SF6 circuit breakers with newer circuit breakers. a demonstration of a mechanism to ensure that the most efficient option to meet a given regulatory driven need is selected.
3. A risk based approach was used to weigh the risk of AAD's assets initiating a bushfire and on that basis evaluate if sections of the Matthews and Reid lines should be replaced with an option that mitigates the risk of bushfire. A costbenefit analysis was undertaken and the outcome was to install Remote Area Power System (RAPS) units and remove sections of the overhead lines feeding the remote loads at Gudgenby Homestead and Corin Dam.
4. A scenario based approach was illustrated to identify potential STIPS benefits in undertaking reliability improvements on poorly performing AAD feeders. The outcome of the cost benefit analysis showed that it was uneconomic to upgrade the worst performing feeder (Macrossan 11kV) with reclosers. This is a further example of efficiency check in planning CAPEX in terms of selection of the most efficient option.

Application Limitations of CAPEX-OPEX trade off

We disagree with the AER that AAD has not considered CAPEX-OPEX trade off issues and have provided examples where the CAPEX-OPEX trade off was used to make significant decision on refurbishment and replacement and timing of augmentations. Apart from the summary provided in this response, detailed discussions on CAPEX-OPEX trade off which were submitted as part of the SRP have been referenced in this response.

CAPEX-OPEX trade-offs are inherent in a number of decisions being made at AAD. CAPEX / OPEX trade-off analysis is, for example, usually undertaken by AAD in the case of refurbishment / replacement of ageing and potentially unreliable equipment, where the ongoing maintenance, repair, and fault costs (including loss of supply) can be compared with the capital cost of refurbishment / replacement. Examples have been provided in the response to Question 2 and also summarised above. CAPEX / OPEX trade-off analysis is also used by AAD when considering the options for use of different types of materials or equipment (e.g. concrete poles vs wood poles vs steel poles vs fibreglass poles). An example of this is the move to fibreglass poles in ‘back yard’ installations to reduce life cycle costs of maintenance of those assets. However, there are limitations in applications of the principle of CAPEX-OPEX trade off in other categories of CAPEX as described below.

CAPEX / OPEX trade-off considerations cannot be usefully applied (or limited opportunities for useful application) to capital projects that are designed to overcome system limitations such as;

- Substation overloads
- Feeder overloads
- Voltage constraints
- New customer connections in areas where there are no existing practical supply points, or increased customer loading.

On Site Generation and CAPEX Reduction

For the above situations there are normally only “CAPEX” options available for projects (including renewables and embedded generation options), not “OPEX” options. In a small number of cases there will be options with a different mix of CAPEX and OPEX costs, and AAD does consider these on a case by case basis. An example of this is the Network Augmentation Report for the installation of Remote Area Power System (RAPS) units to service remote loads at Gudgenby Homestead and Corin Dam.

In another instance, on-site generation is being considered for peak load reduction. Loads from proposed data centres in the vicinity of Mitchell are expected to cause the largest step change in the AAD load over the next 5 years, requiring substantial CAPEX investment over the coming years. AAD is initiating a tripartite discussion with the proponents of the data centres and providers of on-site generation to mitigate the step change in system load due to the continuous and high reliability load requirements of data centres. AAD is facilitating these discussions with clients and generators as part of its demand management strategy. If the on-site generation plan is successful, it will lead to reduced or deferred CAPEX expenditure to meet increased system peak demand

The vast majority of genuine CAPEX / OPEX trade-off evaluations are not analysed on a project by project basis, but on an asset class basis, and AAD has several examples of these referenced in its SRP.

Three examples of such optimisations is summarised in **Attachment B17.1. of AAD's SRP Submission.** Key points of the CAPEX-OPEX trade off issued presented in Attachment B17.1 is given below:

- **Civic Zone Substation – replacement of ageing 11kV switchboard** (implemented 2013)

  AAD and Jacobs (formerly SKM) jointly developed an "Energy at Risk (EaR)" model specifically designed to evaluate the optimum timing for replacement of ageing and potentially unreliable assets including comparison of annualised cost of all maintenance, capital, and energy at risk, to determine the optimum timing for the replacement of the switchgear. The Civic EaR model is based on similar models used by Victorian DNSP's to optimise the timing of augmentation projects, but is more sophisticated in terms of modelling failure rates of plant and equipment nearing the end of its technical life.

  <u>Key features of the EaR model for Civic zone substation were:</u>

  - Modelling specific load duration curves (Summer and Winter) for Civic zone substation,
  - The Value of Customer Reliability (VCR) was adapted from CRA report of 2002, escalated to 2007
  - The model calculated the magnitude and value (at VCR) of energy at risk in Summer and Winter over the period 2007/8 to 2017/18
  - Different values of VCR (from $13,416 to $63,994 per MWhr) were applied for different categories of customer load (e.g. residential, commercial, agricultural, and industrial)
  - The model used internationally available statistics for the probability of failure, and equipment damage,
  - The model took account of load able to be switched away from Civic in the event of a catastrophic fault (3 stages of load transfer and restoration after a fault)

  An NPV analysis of four options was conducted of four options:

  - Option 1 – A "do nothing" option where the ageing switchboard is replaced on failure
  - Option 2 – Replacement of the ageing switchboard I 2013/14 (a slightly deferred date)

- Option 3 – Refurbish the ageing switchboard (and relays) in 2011/12, and defer replacement for 10 years
- Option 4 – Replacement of the ageing switchboard in 2011/12 (earliest possible date)

The NPV analysis of the capital and operating costs of the four options clearly indicated the economic justification for replacement of the ageing Civic switchboard in the 2009-14 regulatory period and the switchboard was replaced in 2013.

This model was subsequently applied to assessing the costs and benefits of replacing the ageing 11 kV switchboard at Civic Zone Substation, which was completed in the 2009–14 regulatory period, and is a case study covered in **Attachment B17.1. of AAD's SRP and section 6.10 - Asset age and replacement/refurbishment modelling of the SRP**.

- **Wood pole replacement with concrete (HV) and fibreglass (LV, rear of block)** – implemented in 2009-14 and ongoing 2014-19. The biggest replacement and renewal expenditure item in this category is the ongoing pole replacement program that was included in the expenditure approved by the AER in the current determination and will continue beyond the 2014–19 regulatory period.

  A detailed description of the cost savings in trading off expensive ongoing maintenance for timber and wood poles to be replaced with poles from alternative materials (fibreglass and concrete) is given in **section 7.8.4 Pole replacement, pole substation and reinforcement programs of AAD's SRP submission.**

- **Underground distribution cable replacement strategy** – implemented in 2013/14, ongoing for 2014/19. Planned replacement of underground cables will commence in 2014/15 as assets reach the end of their useful life, or where replacement becomes an economic alternative to reactive maintenance and replacement. In particular, the program will address an increase in underground cable faults incurred during the current period. Up until now, AAD has adopted the strategy of running the underground cables to failure, and any replacement decisions have been driven by repeated root cause failure. Reactive maintenance expenditure (repairs and replacements) have been increasing throughout the 2009–14 regulatory period. To address this trend AAD has developed an asset management strategy that involves condition monitoring of high voltage underground cables and prioritisation of the high voltage underground cable replacement with suspected problems. **A detailed review of this program is given in section 7.8.5. - Underground cable replacement of the SRP.**

Energy-at-risk modelling optimises project timing by equating the value of energy-at-risk with the annual cost of the specific project required to mitigate the risk. Energy-at-risk modelling is used by the Victorian DNSP's and TNSP, but is only used sporadically by other DNSP's. Energy- at- risk modelling goes further in optimising timing and use of assets than N-1, however does not provide solutions to establish supply for new land releases which have no alternate supply point. New land release developments comprise a significant portion of AAD's augmentation CAPEX.

The project justification reports for developments driven by new land releases take into consideration the amount of reserve capacity that can be practically provided for new developments from existing feeders.

AAD will use the Energy at Risk (EaR) model on a case by case basis as appropriate. Because of the relative smallness of the AAD system, and the infrequency with which major substations or feeders become overloaded there were not many opportunities to apply energy-at-risk modelling. Looking forward at the 2014-19 regulatory period, there are a small number of potential opportunities to apply EaR modelling. Energy at Risk Modelling approach will be considered when the respective project becomes part of the annual works program planning phase (12 to 24 months prior to the project commencement) as part of AAD's Capital Works Approval processes, Projects of note that are included in the SRP and may be suitable candidates for using the EaR models are:

- The timing of the installation of the third transformer at Belconnen ZS
- The timing of the installation of the second transformer at Eastlake ZS
- The timing of the installation of the second transformer at the proposed Molonglo ZS

In undertaking network augmentation for customer initiated works and reliability reinforcements, AAD conducted a review of its 11 kV feeder reliability guidelines in the 2009-14 regulatory period with a view to reducing the extent of inbuilt redundancy on the distribution system, thereby reducing / deferring augmentation expenditure without sacrificing overall reliability of supply to the customer. The outcome of the review was that, the firm rating for feeders with 2 or more ties was raised from 67% to 75% of thermal rating, and augmentation projects being justified on the basis of maintaining contingency reserves be compared to other reliability improvement options on the basis of cost and risk.

The practical outcome of this policy change is that 11 kV distribution feeders are now loaded to higher levels under normal system conditions, prior to augmentation / load relief taking place, and that other more cost effective solutions are researched and implemented wherever possible. This is but one example of cost effective solutions that are researched and implemented by AAD wherever practically possible without compromising system security.

4.4 Productivity and efficiency improvements

AER question

What productivity and efficiency improvements have ActewAGL achieved in the current regulatory period? What is the expected cost saving in dollar term? What improvements has ActewAGL planned for the next period? How were these improvements taken into account in the proposed capex and opex expenditure? Of particular interest is the program which delivers network operation technologies

AAD Response

AAD's investment in network operational technology (OT) in the 2009-14 period was a targeted program aimed at replacing and refreshing critical infrastructure and systems. This program was crucial in enabling the continued delivery of a safe and reliable supply of electricity through the distribution network, ensure compliance with regulatory obligations and to meet emerging consumer engagement requirements.

It was not undertaken with the specific intention of generating future efficiency savings, although AAD acknowledges that there is likely to be a resultant, indirect impact on productivity. These have been included in AAD's operational expenditure forecasts via the implicit productivity improvement described in section 8.7.4 (of the SRP). AAD's opex forecast assumes that the increased costs from output growth, illustrated by a forecast 22% increase in the RAB and 12,000 more customers, will be offset by increases to productivity.

As stated in section 7.12.1 of AAD's subsequent regulatory proposal, prior to this investment in network OT, ActewAGL Distribution's OT environment comprised various disparate systems with asset information spread through a range of heavily customised, off the shelf IT applications, in-house built systems, spread sheets and paper based systems. Interfaces between the systems were limited; integration almost non-existent and extensive manual intervention was required just to meet business needs.

Of greater concern was the number of critical network OT systems that were no longer supported by vendor support arrangements, or were approaching end of useful life. A good example of this is ActewAGL Distribution's billing system which had been built in-house and was no longer covered by a vendor support arrangement. Internal staff who had built the system had left the organisation, and as such the risk of system failure, and its likely impact on the organisation was considered unacceptable. Indeed, the risk to ActewAGL Distribution of system failure, or poor network performance prompted a major shift in ActewAGL Distribution's OT strategy. In addition, it was becoming increasingly apparent that existing systems did not have the capacity to meet emerging regulatory reporting requirements, in particular the level of information required by multiple AER Regulatory Information Notices (RINs), and consumer engagement obligations, including those emerging from the AEMC's Power of Choice review.

In response to these identified risks and emerging obligations, ActewAGL Distribution embarked on the Operational Systems Replacement Program (OSRP) in 2012. In addition to the Distribution Billing System, key OSRP projects undertaken during the 2009–14 regulatory period include implementation of the following systems:

- ADMS/SCADA System: Advanced Distribution Management System (ADMS). GIS-centric, the ADMS (HV Network) is a consolidated SCADA/network modelling system that combines network control and monitoring operational functionalities with network analysis and simulation capabilities;
- Cityworks / Riva: GIS-centric Works and Asset Management System including Strategic Planning; and

- GIS ArcFM: An extension to the existing ESRI ArcGIS system that provides a interconnected network configurable data models critical to effective asset management and real time SCADA operations.

ActewAGL Distribution's proposed Network OT capital expenditure for the 2014–19 regulatory period will complete this regeneration phase, moving ActewAGL Distribution closer to a future state operating environment that is based on a single, completely integrated system that will deliver an end-to-end, geospatially-enabled platform for controlling the network, managing assets, designing and augmenting the network and delivering services to customers. Key projects (outlined by AAD in the SRP) include:

- ADMS LV-HV
- Mobility project
- Customer information and engagement portal.

In addition to these key initiatives the technology roadmap (submitted to the AER on 2 June 2014) provides an investment summary of these and other OT and ICT initiatives and their timing throughout the 2014-19 regulatory period.

A formal governance process will be established to assess each initiative against predefined criteria such as alignment to industry trends, timing of emerging technology adoption and operational readiness considerations to ensure that ActewAGL are implementing an economically sound, industry tested solution.

The OSRP will deliver a 'single source of truth' network technology perspective, which will deliver substantial benefits in terms of improved capital expenditure decision making, improved network performance and increased customer engagement. Realising these benefits will enable AAD to continue to deliver a safe and reliable supply of electricity to its customers, meet regulatory standards and meet emerging customer engagement requirements. Although still in its infancy, the successful implementation of recent and proposed OSRP projects are expected to deliver savings in operational expenditure attributed to:

- The implementation of an integrated end-to-end operational environment will improve productivity by centralising network information as well as reducing double handling of information
- Implementation of network automation along with the advanced distribution management system streamlines the location and repair of network faults, which will allow for reduced reactive maintenance
- Improvements in the quality of asset information will allow for*:*
  - condition based maintenance which will minimise unplanned asset failures and hence the associated expenditure for reactive work;

- the development of Reliability Centred Maintenance plans for nominated asset classes;
- the utilisation of advanced analytical predicative methodologies such as Bayesian Network Analysis.

- The implementation of asset-based works management and reporting enables visibility of all maintenance work and ensures that maintenance activities are tied to asset management plans.

As noted above, these benefits have been implicitly included in AAD's operating expenditure forecast for the 2014/19 regulatory period. This can be illustrated by analysing the opex/customer development forecast for the 2014-19 period, which AAD anticipates to decrease by approximately 6%.

4.5 Major expenditure decisions

AER question

How does ActewAGL ensure that major expenditure decisions are made prudently and correctly? What QA process is place? Of interest here is the major capital investment in Molonglo and Belconnen Zone substations

AAD Response

Scope of response

This response provides the QA process undertaken by AAD to ensure prudency in the decision process and provides evidence of prudency in decision making by way of example through reference to three large augmentation projects the Belconnen third transformer, Molonglo Zone Substation and Extension of the Gold Creek Switch Board that are subject to some degree of uncertainty in terms of the timing of the project.

Capital planning and uncertainty

In relation to the three large augmentation projects, the timing of the solution cannot be established with a high degree of certainty at the start of the regulatory period.

Timing of investment can be established with more certainty closer (18-24 months) to the implementation of the projects. In such cases, it is not prudent for AAD to hold off planning until a high degree of certainty can be established. AAD develops long to medium term capital works plans (5 – 10 year) based on reasonable demand forecast triggers. It would be imprudent for AAD to not take these large anticipated load growth projections into consideration in its planning activities

Prudency and quality assessment

Prudency is the concept of establishing the need for the project, therefore the load forecast information, external stakeholder requirements and the careful consideration of network system capacity (including constraints) are the important elements in establishing the requirement to meet an identified need.

Project Justification Reports (PJR) contain adequate (and 'project maturity' appropriate) information on options analysis undertaken, solutions being proposed, system constraints, demand projections and cost of preferred options. The information checklist which completed alongside the PJR ensures that there is sufficient information to enable prudency for the decision to be considered and determined. SINCAL, a power system simulation software is used to identify available transfer to other substations based on AAD's network model and the information is cross -checked with the operational SCADA systems. The AAD network model is being transitioned to the new (geo spatial centric and real time) ADMS system in the first year of the 2014-19 Regulatory Period.

The identification of potential augmentation need is followed by a process of considering and evaluating options including non-network alternatives. A general review and consideration of options is conducted at the time of the ten-year plan preparation (and reassessed annually). Further detailed assessment of options for specific projects is conducted closer to the proposed project implementation date, prior to obtaining planning and financial approvals.

The PJRs are approved by a person undertaking the review of the document. Typically two network managers approve any PJR being developed. For example, for a report relating to the installation of a transformer, the Asset Strategy and Planning Manager and a second Manager for Primary Systems Strategy would approve the document. The processes for network planning and the expansion process for the Distribution and Asset Strategy groups are provided as figure 4.9.

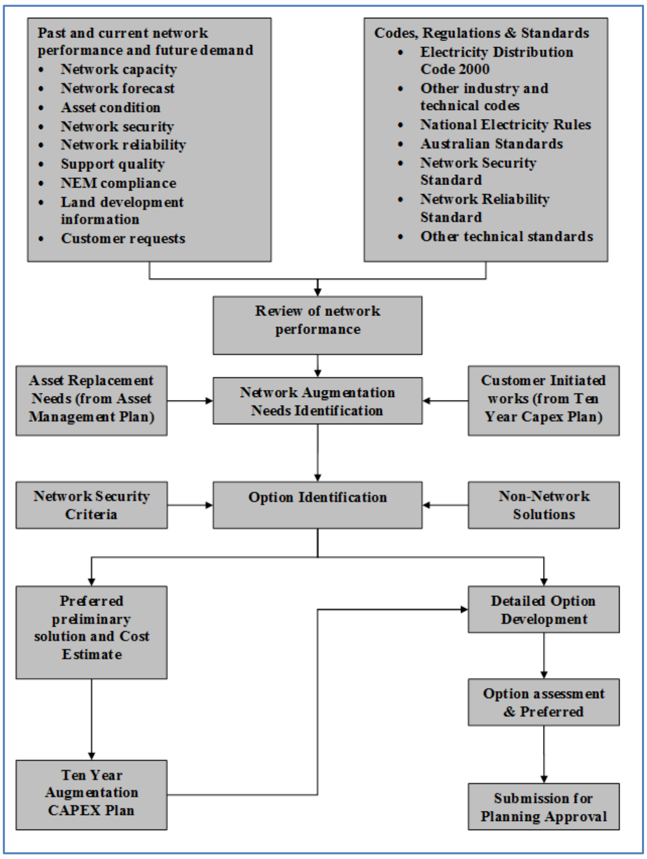
This is a two-stage planning process comprising:

- Stage 1—the basic options are considered and the "most likely option" included in the capital works program; and
- Stage 2—the project and the options are subject to further consideration on the basis of the updated data closer to the implementation date. Before the project is submitted for approval, a detailed assessment of options is conducted. The consideration of options in Stage 2 includes a consideration of possible non-network solutions.

Projects are approved in accordance with AAD's Delegation of Authority process as stated in response to Q1 – refer CAPEX Investment Governance Process. Projects are prioritised in accordance with annual budgetary allowances and deliverability on an iterative basis.

Large distribution projects are subject to the Regulatory Investment Test for Distribution (RIT-D), which provides a transparent framework for decision making and opportunities for parties external to AAD to propose alternative solutions including non-network options. AAD is obliged, under its licence to operation as a DNSP, to consider any options on a non-discriminatory basis as part of the RIT-D process

Figure 4.9 Network planning and expansion process



Molonglo Zone Substation

The Molonglo District is located approximately 10km from the Canberra Central Business District (CBD) and supplied by an existing 11kV feeder - "Cotter") from Woden zone substation. A DA approval has been granted for the development of a substation and a potential substation location has been identified. The planning of the Molonglo Zone Substation has been completed in close consultation with the ACT Government's Land Development Agency.

Whilst feeder augmentation from Woden substation (Streeton and Hilder 11kV feeders can meet short term supply requirements, this will only support projected load growth until 2017/18.

To meet long term demand (beyond 2017/18), a new single transformer 132/11kV substation is the preferred option to supply the Molonglo district for the provision of power to new suburbs in

Molonglo and North Weston. The new zone substation will also have the capability to supply some load in Weston Creek currently supplied by the Woden Zone Substation, thereby deferring the need for capacity augmentation at the Woden Zone Substation for approximately 10 years.

In addition to the proposed substation, the RIT-D Molonglo Zone Substation Report considers alternative feeder supply options, two of these options (as documented in the RIT-D) were discounted early and not progressed and documented in detail. This level of detail, including further discussion of why these alternative feeder options were not considered further will be included in the detailed options analysis and project approval stages.

Further discussion to assist the AER in understanding the planning basis is provided below.

Four (4) existing zone substation facilities within 10km of the proposed Molonglo Zone Substation are considered as potential locations to establish a feeder connection from. The consideration of these options along with the investigation of demand side management options cover the prudency test in that, 'reasonable' solutions available have been considered.

The long distances from Belconnen and Latham zone substations prohibit suitable 11kV feeder implementation and the load forecasts for these substations are approaching the substation reliability ratings. The issue of voltage regulation for feeder options were not costed and considered in detail in the initial options report, however it was not considered prudent to establish feeders with voltage issues from substations that are already loaded close to firm ratings.

A feeder upgrade option from Civic ZS, which is 5km was taken into consideration as a feasible solution. This solution of upgrading the Black mountain feeder from Civic will defer the establishment of the Molonglo ZS by three years; however the long term need is not mitigated entirely. The deferral by three years does not give a Net Present Cost that is significantly different from Net Present Cost of the preferred option. With this option there are numerous planning, approval and consumer issues related to the impact on The National Arboretum Canberra and loading of Civic ZS, which supplies a number of critical loads in the CBD. Network access that has to underpass or bypass waterways would also create a challenge. This solution was not preferred as it did not provide significant benefits. In general, the nature of the terrain, the existence of other developments and infrastructure, and other construction restrictions suggests that it will be difficult to construct additional overhead or underground feeders into the Molonglo area from adjacent zone substations. Therefore, the availability of capacity in adjacent substations cannot be translated directly into available capacity at Molonglo ZS.AAD expects the prudency and efficiency of the Molonglo ZS will be tested rigorously by the RIT-D process.

Gold Creek Switchboard Expansion

Key drivers supporting the forecast growth rate include continued baseline growth in existing residential areas, continued developments in areas such as Casey and Crace, new development areas such as Moncrieff, Taylor and Throsby, and known customer initiated spot loads in the Mitchell area which includes the [redacted]

The above paragraph identifies the load growth in the specific areas and the large spot loads which have a 100% probability of going ahead. The demand forecast provided for the Gold Creek zone substation is consistent in demonstrating this high rate of growth. The total number of feeders required at Gold Creek is shown below.

Figure 4.10 Number of feeders required – Planning

Load Type	Comment	11kV Feeders Required	Recommended Supply Solution
Customer Initiated Loads	Australian Data Centre	1 (a possible 2nd feeder for N-1 security of supply)	Consolidation of Feeders
Customer Initiated Loads	Metronode Data Centre	1	Consolidation of Feeders
New Developments and Dwellings	Period 2015-2020	2	Extension of 11kV Switchboard
New Developments and Dwellings	Beyond 2020	2	Extension of 11kV Switchboard
Total		**6** (potentially 7)	

Capacity is not an immediate concern with Gold Creek zone substation currently operating at around 73% of its emergency rating and expected to only reach the emergency capacity in around 2021, however, the substation does not have any spare 11kV feeder bays to support the expected growth and block load requirements over the next regulatory period and beyond.

The main system constraint justifying this project is that even based on historical demand trends on Gold Creek substation (not including the expected spot load increases at the [redacted]) the underlying demand growth rate for the area is 6% p.a. The demand forecast shows a summer demand increase of 10-12 MVA over the next regulatory period. Gold Creek zone substation is at the northern extremity of the AAD system, with limited distribution transfer capacity to the south and east.

Figure 4.11 Data Centre loads and assessment of probability

Development type	Scope of Work	Expected ADMD Increase (MVA)	Supply Required Date	Project probability
Australian Data Centre	Stage 1: Connection to existing Gungahlin fdrs (2.5 MVA) Stage 2: New Feeder from Gold Creek Sub. (6 MVA) Stage 3: Second fdr from Gold Creek for N-1 security of supply (Refer Network Augmentation Recommendation – 7519031 & 7521445)	6 MVA	Stage 1: FY2014 Stage 2: FY2015 Stage 3: TBD	100%
Metronode Data Centre	Stage 1: Connection to existing fdrs (3.0 MVA) Stage 2: New feeder from Gold Creek (5.4 MVA increasing to 7.4MVA) (Refer Network Augmentation Recommendation – 7521632 & 7522728)	7.4 MVA	Stage 1: FY2015 Stage 2: FY2016	100%

Under such healthy and broadly based demand growth, together with the prospect of possible additional spot loads, it would be imprudent AAD not to install some spare 11kV circuit breakers, which requires the extension of the existing Gold Creek switchboard. It is common practice and minimum prudency for a DNSP to have 1 or 2 spare 11kV circuit breakers on each 11kv zone switchboard in urban areas to cater for generic growth, unexpected spot loads, and the occasional circuit breaker failure.

In addition, the purchase and installation of 11kV circuit breakers is the longest lead time item for establishing new feeders, and can be longer than the lead time given by some project developers for the commissioning of new spot loads.

The PJR considers the option of 'Feeder Consolidation'. The proposed feeder consolidations releases three feeder bays providing a solution for some of the initial 11kV feeder bay requirements associated with customer initiated loads, however, it only provides a partial solution as insufficient feeder bays are released to meet the development growth and longer term network needs. There are no other 'reasonable' options to be considered, thus the PJR demonstrates prudency.

Customer initiated projects generally require an execution timeframe of less than 12 to 18 months to accommodate project schedules. The consolidation of feeders has a relatively short execution timeframe, expected to be less than 6 months, however, additional feeders to accommodate the new developments and dwellings growth cannot be accommodated with the consolidation of feeders and requires further consideration.

Two new feeders are planned with a potential third feeder required for security of supply to the Australian Data Centre, subject to further customer input. In addition, the forecast load growth indicates an increase in base residential demand in the Gold Creek distribution area in excess of

10 MVA over the next five years, with a requirement for at least two feeders within the next regulatory period.

In summary, the PJR for Gold Creek has considered a range of options, including consolidation of feeders, but AAD considers it prudent to invest in the expansion:

- To meet a strong demand growth of 6% p.a.
- To meet likely spot load increases
- To overcome the constraint of no spare 11kV circuit breakers.

Belconnen third transformer

The need for a third transformer at Belconnen is based on the fact that the transformers currently operate on overload of 'firm' ratings. The load forecast from 2015-2023 is a flat load forecast based on the reduced peak demand over the last few years. However, if the suppression of the load of the last few years is lifted, then it is expected that the load will be in excess of the rating of the firm rating of the two transformer substation. Based on this analysis it is prudent to include the Belconnen third transformer in the 2014-19 regulatory period to mitigate the risk of the likely scenario of the Belconnen ZS not being able to meet the supply security criteria. As shared with the AER the annual planning process will review the Belconnen project based on updated demand forecasts and the timing of the project will be revised accordingly. Additional information to describe the rationale for inclusion in the 2014-19 regulatory period based on the likely risk based scenario is provided below.

There was 21% drop in overall system maximum demand in 2012, reflecting an uncharacteristically mild summer which has the impact of artificially suppressing the current load forecast. Therefore, the load forecast is flat from 2015 to 2023, as it was trended on the 2012 forecast. The flat profile is highly unlikely. It is believed that revised forecasts over the next few years will show a significant load at risk. AAD believes that the load at this zone substation will increase and the substation will be overloaded in the next few years, putting load at risk.

<u>Therefore, it is prudent to include the third transformer project into the capital budget and refine the timeframe based on annual review of the load growth at the Belconnen zone substation.</u>

Belconnen zone substation has historically experienced a healthy growth rate, has multiple outgoing feeders, consists of 1-2 substantial spot loads under development and serves as a substation where loads can be transferred from Civic, Latham and Gold Creek substations. Therefore it is not prudent to constrain development as the need for growth is established. In addition, the substation has 2 relatively long lead time items required for development, a transformer and associated switchgear, requiring from 18-24months notice period, where in reality the client may only provide AAD with a 12 month notice period.

<u>Short term increase in capacity rating has been achieved by replacing transformer cables of both transformers to increase the emergency rating available at Belconnen</u>. The possibility of load transfer to nearby substations has also been taken into consideration.

Existing constraints in the ability to transfer loads off Belconnen zone substation mean that the reliability of supply to customers would be compromised under a 'do nothing' option. With Belconnen zone substation operating at its cyclic rating and a high probability that actual demand growth will exceed the forecast and reach the new two hour emergency rating the 'do nothing' option would leave the substation at risk during peak demand periods, and of breaching the security criteria for AAD zone substations.

In the event of a loss of one of the existing 55MVA transformers, there would be a significant load by 2015 that cannot be off-loaded. A failure of a transformer can lead to long lead times for replacement; therefore putting a significant amount of energy at risk. This would be further exacerbated as the future loading approached the two hour emergency rating of the substation resulting in the need to be able to transfer even larger amounts of load during N-1 contingency conditions. In an event that long lead items fail, it is likely that the remaining transformer would be required to operate substantially above its rated capacity for an extended period of time, severely impacting on its operational life, leading to higher or bringing forward (CAPEX) costs in the future.

The size of the third Transformer proposed for Belconnen is determined by the existing transformers. A lower rating transformer applied in parallel would not allow equal load sharing amongst the transformers (generally there will be an impedance difference) and overloading cannot be managed optimally. Therefore, options with smaller sized transformers are not considered and the AAD standard and existing transformers at the substation determine the size of the transformer. Therefore, depending on the load growth, investment may be appropriately timed, but capacity the project provides may stay 'spare' for an extended duration.

AAD believes that it is prudent to make capital budget allowance in the upcoming regulatory period for the Belconnen third transformer.

4.6 Efficiency of operational performance

AER question

How does ActewAGL ascertain whether its operational performances are efficient or not relevant to other network businesses in Australia?

AAD Response

AAD undertakes a range of annual and periodic benchmarking exercises and expenditure reviews to ascertain whether or not its operational performances are efficient. These include, but are not limited to:

1. **Unit rates independently verified** – AAD engaged Jacobs SKM to undertake a comparative review of unit rates for a selection of activities included in AAD's expenditure forecasts for 2009-14. Overall, SKM found that AAD's activity unit rates were reasonable and efficient. This report was provided to the AER as Attachment B11 to AAD's regulatory proposal.

2. **Pole maintenance audit** - An important element of AAD's current pole maintenance strategy is the regular auditing of pole inspection, inspectors, replacement and defect rectification works. Each month a sample of 5-10% of these works are audited by an external party (Electrix Pty Ltd) to assure the quality, safety and cost effectiveness of AAD's pole maintenance and replacement program.
3. **Alliance Agreement value for money check -** This agreement commenced in 2009 and established Zinfra as the major provider of capacity and capability to AAD in respect of major capital works. Under the agreement, AAD appoints an external party to assess the technical validity of the project proposal and whether the target cost estimates are in accordance with current market prices. AAD has undertaken this value for money check for all projects delivered under the Alliance Agreement during the 2009-14 period.
4. **Work package closure process -** At the completion of each capital works package, AAD undertakes a review of the actual expenditure of that package against its estimates and its YTD program forecasts.
5. **Labour cost benchmarking** – In addition to benchmarking Australian salaries and EBA conditions prior the commencement of EBA negotiations every three years, representatives from AAD's people and performance team meet with other industrial relations professionals from a number of the electricity generators and distributors across Australia on a regular basis (usually every 6 months) to discuss IR issues in the industry. Part of that meeting involves an update of any Enterprise Agreement negotiations happening in anyone of the businesses. After the meeting a summary of the EA negotiations in each business is compiled and sent to all attendees. This includes any wage, superannuation and allowance increases and any changes to terms and conditions in Enterprise Agreements.
6. **Expenditure forecasts based on independent cost escalators** – In developing expenditure forecasts, AAD applies price escalation factors that have been developed by external consultants for aluminium, copper, steel, crude oil, labour (utilities, professional services and general), and construction (engineering and non-residential). In developing these escalators, consultants have drawn on a wide range of information including data from market price surveys and industry knowledge obtained from professional estimators, project managers, economists, engineers and operational personnel. This process is discussed in section 7.7.6 of AAD's regulatory proposal.
7. **Reliability studies** – AAD reviews its reliability performance against other DNSPs via annual publications including the *ESAA's Electricity Distribution report* and the AER's *state of the energy market report*.
8. **Tariff comparisons –** network price comparisons contained in AEMC's *Electricity price trends* reports show that AAD has the lowest network prices in Australia.[29] Given AAD's

[29] AEMC 2013, Electricity price trends, Final Report, December

small scale and limited ability to realise economies of scale in the electricity distribution business compared to other DNSPs, this demonstrates a high level of operational performance.

Recent reviews undertaken by the business that have considered AAD's operational performance against other DNSP's or industry best practice include:

1. **Deloitte safety review (2010)** – reviewed AAD's health and safety programs against industry best practice and made a number of recommendations that were implemented during the 2009-14 regulatory period including the establishment of an EHSQ division.
2. **Marchment Hill Consulting review (2011)** – reviewed the organisational structure of AAD's Energy Networks division against industry best practice and made a number of recommendations that were implemented during the 2009-14 regulatory period. The MHC report was provided to the AER on 5 September 2014. Implementation of the report's recommendations was discussed in detail with AER staff at a meeting on 1 October 2014.
3. **McGrath Nichol report (2012)** – review of AAD's corporate cost allocation processes and compared these with the practices of other DNSPs. The report recommended several changes to AAD's cost allocation methodology which were implemented and approved by the AER in June 2013. A copy of the McGrath Nicol report was provided to the AER on 3 September 2014.
4. **IT expenditure benchmarking study (2014)** – a review undertaken by KPMG in April 2014 which benchmarked AAD's ICT investment against other DNSPs. The report found that AAD had 'underinvested' in ICT infrastructure relative to other DNSPs. This report was provided to the AER on 31 July 2014.

4.7 Estimated expenditure

AER question

Where scope and need are unknown or unclear, how does ActewAGL estimate the expenditure in capex and opex?

AAD Response

Scope of Response

The question focuses on the development of a capital works program and the inclusion of projects where the scope and need (prudency) is unknown. An example of the Earth Grid Refurbishment project was raised and is discussed further in the response. It is noted that the AER advised their understanding of the capex cost of the Earth Grid Refurbishment project being $7M. This is incorrect. AAD have reviewed this SRP and associated capital works program and confirm the capex cost is $2.6M

Summary

Below is a four step summary of the generic process undertaken by AAD where scope and need are not known.

1. Where the need is unclear, AAD seeks clarity sufficient to be able to commence its planning stages. The key driver to this is the demand forecast.

   Where scope is unknown, unclear or not fully defined, such as is typical at the early planning stages of a project, or unclear AAD uses good engineering practices to develop a better understanding of the scope throughout a project's life cycle. This is common industry practice as a project proceeds through, for example, stages of: pre-concept, concept, pre-feasibility, feasibility, project definition, project delivery. It is common in industry to recognise the varying levels of engineering and project analysis undertaken and hence available in the development of Project Justification Reports (long term planning and approvals) and Business Cases (short term planning and approvals). Similarly, the accuracy of the budgetary estimates at these stages varies accordingly.

2. A typical method of seeking definition sufficient to enable planning to commence for an, initially, unclear scope is to undertake sufficient minimal works to clarify the scope (and risk). This is often a 2 staged approach where a budget will be established to complete the phase 1 'scope definition' and phase 2 for the 'project delivery'.

   When planning for the Earth Grid Refurbishment program, AAD's approach is based on assessing the likely outcome and benefit of the works (on a prudency and efficiency basis) and to seek approval for long term funding on that basis. This capital funding for this program is based on a phase 1 'scope definition' budget for each of the 15 sites and a notional 'refurbishment budget' for each of the 15 sites. It is expected that a similar cost will be incurred for each site for phase 1, while phase 2 will have refined costs for each substation.

3. The AER advised that the Earth Grid Refurbishment program was $7M over 5 years. AAD has reviewed its records and the SRP and note that this program is $2.6M over 5 years. It is not clear where the AER has sourced its information from to arrive at its $7M. As further basis for the AER in understanding AAD's approach to this program that is largely unknown the following information is provided to assist the AER in better appreciating the good engineering and economic practices to ensure prudency and efficiency of expenditure in this case.

Condition – Earth Grids

The earth grids at AAD Distribution's zone stations were installed when the stations were first developed and hence range in ages of several years up to 46 years, with the majority being over 25 years of age. As the earth grids are buried beneath the station surfaces, and most likely beneath at least some equipment foundations, their widespread exposure for physical inspection is not practical and could not be easily achieved. As such the physical condition of the earth grids, particularly those of the greatest age, is largely unknown.

In light of their unknown physical condition and the increase in network fault levels over time, the effectiveness of the earth grids and hence the level of safety provided at each station is uncertain. It is proposed to undertake a staged program of inspection, electrical testing e.g. earth impedance and resistivity testing, and refurbishment/upgrading the station earth grids as necessary. The exact scope of the resultant augmentation or replacement works is unknown until condition monitoring/inspection/testing has been undertaken (phase 1), for which a budget needs to be provisioned. However, a reasonable estimate of the scope of augmentation or replacement works (phase 2) based on age, known soil conditions and fault level changes can be estimated using experience and engineering knowledge and judgement.

A number of AAD's zone substations are over 30 years old with no condition assessment details available on their earthing grids. An earthing grid's location (type of soil – reactive or non-reactive), severity of the faults interrupted, physical damage and other factors (e.g. moisture in soil, ground movement) can impact the earthing grid resistance which is vital for public and staff safety and also for operation of network protection relays. Therefore, it is necessary for AAD to determine the current state of these aged earthing grids through condition assessment testing, and to undertake necessary remedial works promptly to mitigate risks associated with the deterioration in order to ensure that AAD fulfils its duty of care and regulatory obligation with respect to safe and efficient operation of its network.

As explained in the summary, for each sub-station, the program is comprised of two phases:

- Phase 1 incorporates the sample inspections, electrical testing and overall condition assessment of the earth grids.
- Phase 2 covers the refurbishment and upgrading as necessary of the earth grids as determined by Phase 1 outcome.

Basis of Estimate - Earth Grid Upgrade Project

A reasonable basis for establishment of an expenditure budget is to assume an age based condition and hence a proportionate level of potential refurbishment works. While the actual works would be condition based, an aged based estimate is prudent and provides a basis for cost estimate, in the absence of further refined information. This is standard utility practice, particularly when managing a portfolio of similar asset types, where some will have a condition better than expected and some worse but, on average, the overall condition of the assets will be as would be expected from previous engineering experience and knowledge.

There are four levels of earth grid upgrade costs provided by an independent contractor based on the age profile. These estimate costs are in accordance with those necessary to provide a preliminary forecast budget. The estimates will be refined as scope of each substation works becomes clear and after 'market testing' of contractors' prices at the next stages of the project. A further age related rationalisation is undertaken as the project matures and gets closer to being included in the annual works program. This allocates major and minor works and validates the overall requested program expenditure.

Attachment A – Huegin report

Attachment B – Asset age comparison